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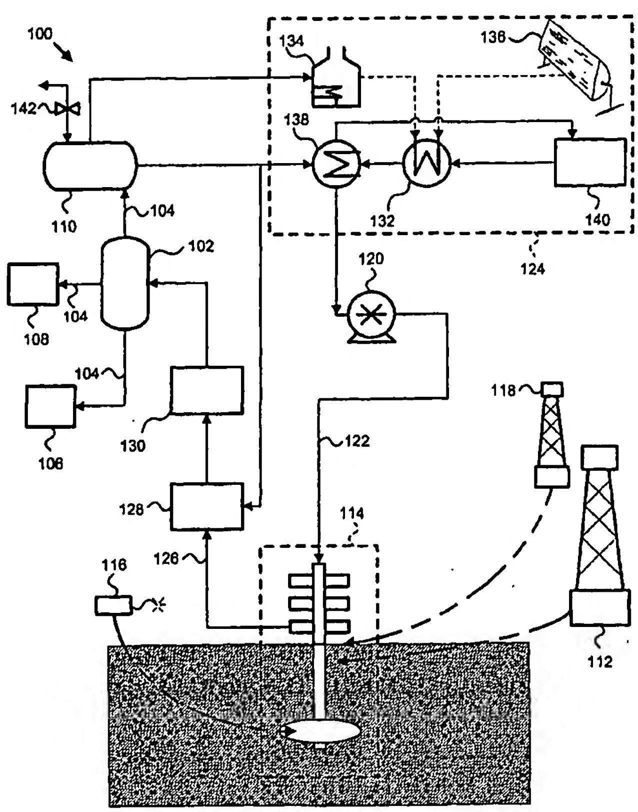
(54) Title: APPARATUS, SYSTEM, AND METHOD FOR IN-SITU EXTRACTION OF OIL FROM OIL SHALE



(57) Abstract: An apparatus, system, and method are disclosed for in-situ extraction of oil from oil shale. The method comprises drilling a fluid conduit (114) in fluid communication with a top and a bottom of a target zone (210) within an oil shale formation. The method includes stimulating the target zone (210). The method further includes injecting a heated fluid (122) into the bottom of the target zone (210) such that the heated fluid (122) entrains the kerogen within the target zone (210) into the injected fluid (122) to generate a production fluid (126). The method concludes with producing the production fluid (126), containing the in-situ kerogen, from the top of the target zone (210) to the surface.

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APPARATUS, SYSTEM, AND METHOD FOR IN-SITU EXTRACTION OF OIL FROM OIL SHALE

BACKGROUND OF THE INVENTION

FIELD OF THE INVENTION

This invention relates to the production of oil from oil shale, and more particularly relates to stripping in-situ kerogen from an oil shale formation.

DESCRIPTION OF THE RELATED ART

One of the last great untapped fossil fuel resources is oil from oil shale. Traditional oil production methods do not pull oil from shale because the oil contained within oil shales is stored as kerogen and will not flow from the shale formation. Kerogen is a high molecular weight hydrocarbon requiring temperatures over 300 degrees C before it will break down and separate from the formation rock.

The conventional art for removing oil from oil shale is not economical, requiring shale formations with high oil content, and sustained high oil prices. For example, the oil shale deposits in Eastern Utah vary between 10 and 60 gallons of oil per ton of shale formation, and most conventional practices are only projected to be profitable above 25 gallons of oil per ton, meaning many formations are not suitable for these practices. Therefore, commercial oil shale production is not yet available on a large scale.

One example of a conventional practice for oil shale production is an in-situ conversion process (ICP) developed by Shell. In the ICP process, a large number of wells are drilled around a target zone, and a refrigerant is circulated through these wells to create an ice seal around the target zone and prevent formation water from migrating into the target zone. Then, two wells are drilled into the center of the target zone. The water already within the target zone is pumped out, an electric heater is placed within one of the wells, and oil is pumped out the other well as it is heated.

The ICP process covers the basic principles needed to remove oil from oil shale. First, the water in the target zone must be removed or displaced to allow the temperature in the target zone to reach the required level. Then, a large amount of thermal energy is required before the oil can be extracted. The ICP process has the disadvantage of requiring a large number of drilled wells, as well as the pumping losses and cooling requirements of the refrigerant wells.

Another example of a conventional practice for oil shale production is a strip mining process. An oil shale formation is mined and the bulk material treated at the surface to remove the kerogen. While this process is simple, it introduces a number of environmental issues which

must be resolved. First, strip mining itself changes the landscape dramatically, and it can require many years before the land is again available for other purposes. Second, the bulk oil shale material, even when stripped of kerogen, may contain oil and chemical residues that present a disposal problem.

Another example of a conventional practice for oil shale production is an underground room and pillar mining process. The process is expensive and leaves significant amounts of kerogen in place as support for the mining chambers. The process is only economical in shallow shales (perhaps less than 1000 feet deep) and it requires minimum formation thicknesses of 50 to 100 feet. Again the bulk oil shale material requires disposal in this mining process.

From the foregoing discussion, it should be apparent that a need exists for an apparatus, system, and method that allows for the economic removal of oil from oil shale. Beneficially, such an apparatus, system, and method would strip the oil from the shale in-situ, and maximize the efficiency of the large amounts of thermal energy required to remove the oil from the shale formation.

SUMMARY OF THE INVENTION

The present invention has been developed in response to the present state of the art, and in particular, in response to the problems and needs in the art that have not yet been fully solved by currently available oil shale extraction systems. Accordingly, the present invention has been developed to provide an apparatus, system, and method for extracting oil from oil shale that overcome many or all of the above-discussed shortcomings in the art.

An apparatus is disclosed for extracting oil from oil shale. The apparatus may include a drilling unit for drilling a well to fluidly communicate with the top and bottom of a target zone of an oil shale formation. The apparatus may also include a stimulation module configured to stimulate the target zone. The apparatus may further include a completion unit configured to position an injection tube substantially at the bottom of the target zone, and an injection unit configured to inject a fluid into the target zone. The injection unit may be configured to inject the fluid into the target zone such that the fluid displaces free water within the target zone. The injected fluid may be commercial natural gas and/or produced natural gas from the well.

The apparatus may include a thermal delivery unit configured to heat the fluid such that the heated fluid entrains in-situ kerogen to generate a production fluid. The thermal delivery unit may be configured to heat the fluid at the surface using a solar concentrator and/or a gas burner. The thermal delivery unit may comprise a downhole burner configured to heat the fluid in the well without introducing combustion byproducts into the fluid. In one embodiment, the

apparatus may include a circulation unit to circulate the fluid through an offset well to preheat the fluid before heating of the fluid by the thermal delivery unit.

The apparatus may further include a production module, which may be a tube, to produce the production fluid. The apparatus may include a treatment module configured to heat the production fluid to a target temperature, add natural gas to provide excess hydrogen if needed, and react the production fluid on a catalytic reactor. The treatment module may thus break the hydrocarbons of the production fluid into smaller, more commercially valuable hydrocarbons.

The stimulation module may be further configured to stimulate a second target zone, which may be in the well in a higher location than the first target zone. The completion unit may be configured to position the injection tube substantially at the bottom of the second target zone. The apparatus may further include an isolation unit configured to isolate the well from the first target zone. The injection unit may be further configured to inject the fluid into the second target zone. The thermal delivery unit may be further configured to heat the fluid such that energy of the heated fluid entrains in-situ kerogen within the second target zone to generate the production fluid.

A method is disclosed for extracting oil from oil shale. The method may comprise drilling a well to fluidly communicate with the top and bottom of a target zone. The well may include one or more wells, and the well(s) may be vertical or horizontal wells. The method may further include stimulating the target zone, and positioning an injection tube substantially at the bottom of the target zone. The method may then include injecting a fluid into the target zone, and heating the fluid such that the heated fluid entrains in-situ kerogen to generate a production fluid. The method may include producing the production fluid. The method may conclude with heating the production fluid to a target temperature and treating the production fluid in a catalytic reactor to reduce the average molecular weight of the entrained kerogen. The method may further comprise adding natural gas to the production fluid such that a minimal amount of hydrogen is available for reaction within the catalytic reactor

In one embodiment, the method may include positioning a production tube substantially at the top of the target zone, where producing the production fluid comprises flowing the production fluid up the production tubing. The method may include setting a production casing through the oil shale formation, and perforating the production casing substantially near the bottom of the target zone, perforating the production casing substantially near the top of the target zone. Where the method includes a production casing, positioning the injection tube further comprises positioning the injection tube within the production casing, and producing the production fluid may comprise flowing the production fluid up the annulus formed between the

production casing and the injection tubing. Flowing the production fluid up the annulus formed between the production casing and the injection tubing may include positioning a production tube within the annulus, and producing the production fluid up the production tube.

A system is disclosed for in-situ extraction of oil from oil shale. The system may include a three-phase separator configured to separate a production fluid into oil, water, and natural gas, and fluid coupling configured to deliver separated water to a water disposal system, to deliver separated oil to an oil storage facility, and to deliver separated natural gas to a natural gas storage facility. The system may further include a drilling unit for drilling a well to fluidly communicate with the top and bottom of a target zone of an oil shale formation. The system may also include a stimulation module configured to stimulate the target zone. The system may further include a completion unit configured to position an injection tube substantially at the bottom of the target zone, and an injection unit configured to inject a fluid into the target zone. The injection unit may be configured to inject the fluid into the target zone such that the fluid displaces free water within the target zone. The injected fluid may be commercial natural gas and/or produced natural gas from the well.

The system may further include a production module, which may be a tube, to produce the production fluid. The system may include a treatment module configured to heat the production fluid to a target temperature, add natural gas to provide excess hydrogen if needed, and react the production fluid on a catalytic reactor. The treatment module may thus break the hydrocarbons of the production fluid into smaller, more commercially valuable hydrocarbons. The system may also include a condensing module configured to cool the reacted production fluid and deliver the cooled fluid to the three-phase separator.

Reference throughout this specification to features, advantages, or similar language does not imply that all of the features and advantages that may be realized with the present invention should be or are in any single embodiment of the invention. Rather, language referring to the features and advantages is understood to mean that a specific feature, advantage, or characteristic described in connection with an embodiment is included in at least one embodiment of the present invention. Thus, discussion of the features and advantages, and similar language, throughout this specification may, but do not necessarily, refer to the same embodiment.

Furthermore, the described features, advantages, and characteristics of the invention may be combined in any suitable manner in one or more embodiments. One skilled in the relevant art will recognize that the invention may be practiced without one or more of the specific features or advantages of a particular embodiment. In other instances, additional features and advantages

may be recognized in certain embodiments that may not be present in all embodiments of the invention.

These features and advantages of the present invention will become more fully apparent from the following description and appended claims, or may be learned by the practice of the invention as set forth hereinafter.

BRIEF DESCRIPTION OF THE DRAWINGS

In order that the advantages of the invention will be readily understood, a more particular description of the invention briefly described above will be rendered by reference to specific embodiments that are illustrated in the appended drawings. Understanding that these drawings depict only typical embodiments of the invention and are not therefore to be considered to be limiting of its scope, the invention will be described and explained with additional specificity and detail through the use of the accompanying drawings, in which:

Figure 1 is a schematic block diagram depicting one embodiment of a system for removing oil from oil shale in accordance with the present invention;

Figure 2 is a schematic block diagram depicting one embodiment of at least one fluid conduit to a top of a target zone and a bottom of a target zone of an oil shale formation;

Figure 3 is a schematic block diagram depicting one embodiment of a treatment module in accordance with the present invention;

Figure 4 is a schematic block diagram depicting one embodiment of a downhole burner in accordance with the present invention;

Figure 5 is an illustration of one embodiment of a second target zone in accordance with the present invention;

Figure 6 is a schematic block diagram depicting an alternate embodiment of a at least one fluid conduit to a top and a bottom of a target zone in accordance with the present invention;

Figure 7 is a schematic block diagram depicting one embodiment of heating a hydrocarbon gas in accordance with the present invention;

Figure 8A is a schematic block diagram depicting one embodiment of a first and second horizontal well segment in accordance with the present invention;

Figure 8B is a schematic block diagram depicting an alternate embodiment of a first and second horizontal well segment in accordance with the present invention;

Figure 9 is a schematic block diagram depicting one embodiment of a first, second, and third horizontal well segment in accordance with the present invention;

Figure 10A is an illustration of a well spacing in accordance with the present invention;

Figure 10B is an illustration of an alternate well spacing in accordance with the present invention;

Figure 11 is an illustration of a thermodynamic equilibrium chart for heavy hydrocarbons in the absence of excess hydrogen;

Figure 12 is an illustration of a thermodynamic equilibrium chart for heavy hydrocarbons in the presence of excess hydrogen;

Figure 13 is a schematic flow diagram of a method for extracting oil from oil shale in accordance with the present invention;

Figure 14A is a schematic flow diagram of a method for extracting oil from an oil shale comprising a first and second target zone in accordance with the present invention;

Figure 14B is a schematic flow diagram of a method for extracting oil from an oil shale comprising a first and second target zone in accordance with the present invention;

Figure 15A is a schematic flow diagram of a method for extracting oil from an oil shale, the method comprising drilling at least one horizontal well segment, in accordance with the present invention; and

Figure 15B is a schematic flow diagram of a method for extracting oil from an oil shale, the method comprising drilling at least one horizontal well segment, in accordance with the present invention.

DETAILED DESCRIPTION OF THE INVENTION

It will be readily understood that the components of the present invention, as generally described and illustrated in the figures herein, may be arranged and designed in a wide variety of different configurations. Thus, the following more detailed description of the embodiments of the apparatus, system, and method of the present invention, as presented in Figures 1 through 15B, is not intended to limit the scope of the invention, as claimed, but is merely representative of selected embodiments of the invention.

Reference throughout this specification to "one embodiment" or "an embodiment" means that a particular feature, structure, or characteristic described in connection with the embodiment is included in at least one embodiment of the present invention. Thus, appearances of the phrases "in one embodiment" or "in an embodiment" in various places throughout this specification are not necessarily all referring to the same embodiment.

Furthermore, the described features, structures, or characteristics may be combined in any suitable manner in one or more embodiments. In the following description, numerous specific details are provided, such as examples of materials, fasteners, sizes, lengths, widths, shapes, etc., to provide a thorough understanding of embodiments of the invention. One skilled in the

relevant art will recognize, however, that the invention can be practiced without one or more of the specific details, or with other methods, components, materials, etc. In other instances, well-known structures, materials, or operations are not shown or described in detail to avoid obscuring aspects of the invention.

Figure 1 is a schematic block diagram depicting one embodiment of a system 100 for removing oil from oil shale in accordance with the present invention. The system 100 may comprise a three-phase separator 102 configured to separate a production fluid into oil, water, and natural gas. The system 100 may further include fluid coupling 104 configured to deliver separated water to a water disposal system 106, to deliver separated oil to an oil storage facility 108, and to deliver separated natural gas to a natural gas storage facility 110.

The system 100 may further comprise a drilling unit 112 configured to drill at least one fluid conduit to a top of a target zone and a bottom of the target zone of an oil shale formation. The fluid conduit(s) to a top of a target zone and a bottom of the target zone of an oil shale formation may comprise a well 114. The well 114 may comprise one or more vertical wells 114, and/or one or more horizontal wells 114. The target zone may comprise a region within an oil shale formation from which the system 100 will remove the oil from the oil shale. Some of the details of one embodiment of a well 114 are shown in Figure 2 for clarity. The drilling unit 112 may comprise a coiled-tubing drilling unit, or a standard drilling rig.

The system 100 may further comprise a stimulation module 116. The stimulation module 116 may comprise an explosive device, a hydraulic fracturing unit, a matrix acid unit, and/or other stimulation units known in the art. In one example, the stimulation module 116 comprises an explosive device configured to detonate within the target zone, and create a semi-spherical fractured region around the wellbore of the well 114, with approximately a 90 foot radius and a 45 foot height. The stimulation module 116 may comprise multiple explosive devices depending upon the fracture capability of a given device, and the size of the intended target zone.

The system 100 may further comprise a completion unit 118 configured to position an injection tube substantially at the bottom of the target zone. Positioning as used herein describes the placement and positioning of the injection tube outlet, where the injection tube inlet may be at the wellhead of the well 114, at the surface, on a coiled tubing unit, or at some other location depending upon the specific embodiment of the invention. The completion unit 118 may comprise a workover rig, a completion rig, or a coiled tubing unit. Any other type of tubing placement equipment suitable to place injection tubing in the well 114 is considered a completion unit 118 within the scope of the invention.

The system 100 may have an injection unit 120 configured to inject a fluid 122 into the target zone. The fluid 122 may comprise any gas compatible with the formation, and may typically comprise natural gas, nitrogen, water vapor, and carbon dioxide. Without limitation, the fluid 122 may also comprise carbon monoxide, helium, hydrogen, argon, neon, methane, ethane, propane, butane, and the like. The injection unit 120 may be configured to inject the fluid 122 into the target zone such that the fluid 122 displaces free water within the target zone 210 (see Figure 2). In one embodiment, the fluid 122 is injected at a pressure higher than a fluid pressure of the formation and lower than a fracture pressure of the formation. In one example, an oil shale formation comprises a fluid formation pressure of about 1300 psig, and a fracture pressure of about 2100 psig, at a formation depth of about 3000 feet.

The injection pressure for displacement of free water is measured at the formation depth (the "downhole pressure"). It is within the skill of one in the art to estimate the downhole pressure from the surface pressure, or to place a downhole pressure device in formations where small differences between the fracturing pressure and the formation fluid pressure require greater accuracy than surface estimates allow.

The system 100 may include a thermal delivery unit 124 configured to heat the fluid 122 such that the heated fluid 122 entrains in-situ kerogen to generate a production fluid 126. The system 100 may include a treatment module 128 configured to heat the production fluid 126 to a target temperature and to react the production fluid 126 in a catalytic reactor. Further details of one embodiment of a treatment module 128 are provided in reference to Figure 3. The system 100 may further include a condensing module 130 configured to cool the production fluid 126 and to deliver the reacted production fluid 126 to the three-phase separator 102.

The thermal delivery unit 124 may be configured to heat the fluid 122 at the surface as shown in the embodiment of Figure 1, or to heat the fluid 122 closer to the target zone, for example within the well 114. The thermal delivery unit 124 may include an oil heater 132 configured to receive heat from a natural gas burner 134, and/or from a solar concentrator 136. The thermal delivery unit 124 may further include a heat exchanger 138 configured to transfer the heat from the oil heater 132 to the fluid 122. The unit 124 may cycle oil from an oil sump 140, through the oil heater 132, and through the heat exchanger 138, before returning the oil to the oil sump 140. Other methods of collecting heat from the natural gas burner 134 and/or the solar concentrator 136 are known in the art, and these are contemplated within the scope of the invention.

The heated fluid 122 entrains in-situ kerogen over a period of time. The fluid 122 begins heating the formation from the well 114 outward into the target zone 210 of the formation. After

a period of time, the kerogen breaks down, releases from the oil shale, and is entrained into the fluid 122 to generate the production fluid 126. Eventually, the entire target zone 210 treated by the injection of the fluid 122 becomes substantially depleted of kerogen, and the oil cut of the production fluid 126 drops to the point where further operation of the system 100 to remove oil from the oil shale is no longer economical.

In one example for general guidance, using methane at 400 degrees C as the heated fluid 122, the fluid 122 is injected at 2,300 cubic feet per minute, and approximately 60% of the in-situ kerogen from the target zone is estimated to be extracted from a well 114 draining a 0.72 acre area, with a 100 foot thick target zone, within one year. The exact temperatures, injection rates, and depletion times depend upon the characteristics of the individual formation and kerogen within that formation, the specific costs of drilling, heating, and pumping the fluid 122 and are calculations within the skill of one in the art in light of the disclosures herein.

Generally, temperatures below 300 degrees C may not break down and entrain kerogen except in oil shale formations where the kerogen may have a very low base molecular weight. Consequently, the system 100 operates with a preferred temperature for the fluid above 300 degrees C. Economic considerations such as the desired time to produce a target zone to depletion may drive the temperature determination even higher than 400 degrees C which will break down and entrain most kerogens. These determinations can be made from a simple core sample test of the oil shale formation and the economics of a given embodiment of the system 100, and are within the skill of one in the art.

The system 100 may include a production module (shown in Figure 2) configured to produce the production fluid 126 from the formation to the surface. In the context of the present invention, producing the production fluid 126 means flowing the production fluid 126 to the surface, either through the inherent pressure within the fluid 126, or through artificial means such as pumping or the like.

The natural gas storage facility 110 may be configured to provide natural gas to the natural gas burner 134, to provide natural gas to the injection unit 120, perhaps through the heat exchanger 138, and to provide natural gas to the treatment module 128. The natural gas storage facility 110 may be connected to an external gas source through a control valve 142, and may be configured to receive gas from the external gas source, or to deliver excess produced gas to the external gas source.

The system 100 may comprise various temperature, pressure, and fluid density sensors, control valves, and electronic or other controls to utilize these features. These sensors and

controls are known in the art, and are omitted from the system 100 shown in Figure 1 to avoid obfuscating features of the illustrated embodiment of the invention.

Figure 2 is a schematic block diagram depicting one embodiment of at least one fluid conduit 114 to a top of a target zone and a bottom of a target zone of an oil shale formation, where the at least one fluid conduit in Figure 2 comprises a well 114. The features shown in Figure 2 indicate functional relationships only and are not drawn to scale. For example, the depth of the oil shale formation 212 from the surface may vary from near the surface to several thousand feet. The well 114 may include a wellhead 202 configured to allow the introduction and expulsion of fluids from the well 114, and to contain any pressure from the well 114. The well 114 may form a fluid conduit 204 to the top of a target zone 210 of an oil shale formation 212, and a fluid conduit 206 to the bottom of the target zone 210 of the oil shale formation 212.

The stimulation module 116 may be configured to stimulate the target zone 210, and thereby create at least one stimulated region 214. In one embodiment, a fractured semi-spherical region 214 is created from an explosive fracturing device. Where the target zone 210 is taller than the stimulated region 214 from a single explosive device, multiple explosions may be used to stimulate as much of the target zone 210 as economic considerations dictate. In the example shown in Figure 2, the stimulation module 116 created two stimulated regions 214 each about 45 feet tall and 90-foot radius, where the target zone 210 is about 100 feet thick (tall) and 200 feet in diameter.

The well 114 may include a production module 216 configured to produce the production fluid 126. The production module 216 may be a production tube 216 positioned substantially at the top of the target zone 210. Ideally, the production module 216 will draw fluid from the target zone 210 at the top of the target zone 210, but design considerations and physical constraints of the system 100 may require the production module 216 to draw fluid from above or below the top of the target zone without detriment to the functioning of the present invention.

For example, in deep wells the exact placement of the end of the production tube 216 may be uncertain to within a range of several feet without the use of expensive logging tools to place the end of the tube 216. The invention does not require that such error be accounted for. In another example, the system 100 may be designed such that a second target zone (refer to Figure 5) will be completed above the first target zone 210 at a later time. In the example, the placement of the production tube 216 may be 10 feet (or more) above or below the top of the target zone 210 to allow for a cement plug or other isolation mechanism to isolate the first and second target zones. These allowances are within the margin indicated by a production tube 216 positioned substantially at the top of the target zone 210.

The system 100 may include an injection tube 218 positioned within the well 114 substantially at the bottom of the target zone 210 of the oil shale formation 212. As with the production tube 216, the exact placement of the injection tube 218 is not critical, although ideally a position at the bottom of the target zone 210 is desirable. The injection unit 120 may further comprise isolation 220 within the well 114, such that injected fluid 122 enters the target zone 210. The isolation 220 may comprise a cement plug, a pair of bridge plugs – one at the top and one at the bottom of the region 220 – or the like.

In one embodiment, the fluid 122 comprises a fluid heated at the surface, and the injection tube 218 comprises a vacuum insulated tube. The vacuum insulated tubing may comprise a k-factor of 0.006 to 0.02 BTU/hr-ft-degF, or about 5000 times lower than the k-factor of standard production steel tubing. The fluid 122 may be heated at the surface using combusted natural gas (134, 132, 138), a solar concentrator 136, and/or through recirculation of the fluid 122 through an offset depleted well (see Figure 7).

The well 114 may include an upper isolation 222 configured to prevent exposure of the backside of the production tube 216 to the production fluid 126. The upper isolation 222 is not necessary for the proper function of the invention, but in some embodiments the upper isolation 222 may be desirable to protect the production tube 216 from unnecessary exposure to contaminants.

The embodiment of Figure 2 illustrates an open-hole completion, or a producing well 114 without casing set through the target zone 210. The well 114 may be a cased well, as indicated by an embodiment of a well 114 illustrated in Figure 6.

Figure 3 is a schematic block diagram depicting one embodiment of a treatment module 128 in accordance with the present invention. The treatment module 128 may be configured to heat the production fluid 126 to a target temperature and to react the production fluid in a catalytic reactor 302. This reduces the average molecular weight of the entrained kerogen in the production fluid 126. A typical kerogen will exceed twenty carbons per hydrocarbon molecule, although the extracted kerogen will also produce a significant amount of natural gas which is generally considered one to four carbons per molecule. Hydrocarbons roughly around ten carbons per molecule are generally much more commercially desirable than the large hydrocarbons over twenty carbons per molecule.

In one embodiment, the treatment module 128 receives natural gas 304 from the natural gas storage facility 110, combusts the natural gas in a burner 306, and heats the production fluid 126 in a heat exchanger 308 with the combusted gas 310. The amount of gas 304 to be combusted will depend upon the mass and heat capacity of the production fluid 126, the energy

in the gas 304, the efficiency of the burner 306 and heat exchanger 308, and the target temperature. The sensors and controls to implement the heating controls are known in the art and not described herein to avoid obscuring aspects of the invention.

The treatment module 128 may include scrubbing contaminants from the production fluid 126 before treating the production fluid 126 in the catalytic reactor 302. Among the contaminants which may be present in the production fluid 126 are sulfur compounds, nitrogen compounds, and heavy metals or metalloids such as arsenic. The scrubbing may be performed before or after heating the production fluid 126 in the heat exchanger 308, although separating before heating may lower the heat burden of the heat exchanger 308. Various scrubbing systems are known in the art.

The treatment module 128 may be configured to react the production fluid 126 in a catalytic reactor 302 after heating. A standard platinum-based catalyst may be used in the catalytic reactor 302, although many catalytic systems are known that lower the activation energy of the hydrocarbon cracking reaction and thereby reduce the time to thermodynamic equilibrium. These systems are contemplated within the scope of the invention. Catalyst selection and sizing of the reactor 302 depends upon the specific composition of the production fluid 126. The catalyst and sizing selections are within the skill of one in the art, and can be determined for a particular production fluid 126 with simple and straightforward field experiments.

When cracking large hydrocarbon molecules into smaller hydrocarbon molecules, the presence of excess available hydrogen makes smaller hydrocarbons the favored thermodynamic product. To ensure the thermodynamics favor the production of small hydrocarbons, where the production fluid 126 does not contain enough methane and other light-end hydrocarbon gases, the treatment module 128 may add natural gas 304 to the production fluid 126 before heating in the heat exchanger 308. In one embodiment, a preferred ratio is at least one free methane for each large hydrocarbon molecule, or about 5% by weight methane. The ratios for specific embodiments vary with the compositions of the available natural gas 304, the production fluid 126, the target temperature, and the catalyst type and loading on the reactor 302, and can be calculated by one of skill in the art based on the data for the contemplated embodiment and the disclosures herein.

Figure 4 is a schematic block diagram depicting one embodiment of a downhole burner 402 in accordance with the present invention. The thermal delivery unit 124 may comprise a downhole burner 402 configured to heat the fluid 122 within the at least one fluid conduit (the well 114) to the bottom of the target zone 210. The downhole burner 402 may combust a heating

fluid 404 within the well 114. The heating fluid 404 may comprise a mixture of natural gas and oxygen (or air). The burner 402 may pass the combusted heating fluid 406 through a heat exchanger 408 to heat the fluid 122 in the injection tube 218.

The use of a downhole burner 402 may be combined with surface heating of the thermal conduit fluid 124 and/or vacuum insulated tubing 218. Without limitation, the combination is especially appropriate with passive heating mechanisms such as the use of solar concentrators 136 and recirculation through an offset well (see Figure 7). In one embodiment, the majority of the injection tube 218 comprises vacuum insulated tubing, while the tube section exposed to the heat exchanger 408 comprises standard tubing.

Figure 5 is an illustration of one embodiment of a second target zone 502 in accordance with the present invention. The stimulation module 116 may be further configured to stimulate 514 the second target zone 502, and the completion unit 118 may be further configured to position the injection tube 218 substantially at the bottom of the second target zone 502. The system 100 may further comprise an isolation unit (not shown) configured to isolate 504 the portion of the fluid conduit 114 in fluid communication with the first target zone 210 from the portion of the fluid conduit 114 in fluid communication with the second target zone 502. The isolation unit may comprise a cementing unit configured to place a cement plug 504, and/or a completion unit 118 to place a bridge plug 504.

The injection unit 120 may inject the fluid 122 into the second target zone 502. The thermal delivery unit 124 heats the fluid 122 such that the energy of the heated fluid 122 entrains in-situ kerogen in the fluid 122 to generate the production fluid 126.

In the example of Figure 5, the completion unit 118 may be configured to isolate 522 the production tube 216 from the wellbore above the second target zone 502, and to isolate 520 the injection tube 218 from the production tube 216 such that the injected fluid 122 flows through the second target zone 502. The injection tube 218 may be configured to inject the fluid 122 above or below a prior isolation 222 for the first target zone 210. The injection tube 218 is shown in the example injecting the fluid 122 below the previous isolation 222.

Figure 6 is a schematic block diagram depicting an alternate embodiment of at least one fluid conduit 114 to a top and a bottom of a target zone 210 in accordance with the present invention. The primary difference in the embodiment of Figure 6 from the embodiment of Figure 2 is that the embodiment of Figure 2 is an open-hole completion while the embodiment of Figure 6 is a completion with casing 602 set within the target zone 210, and wherein the fluid communication between the fluid conduit(s) 114 to the top and bottom of the target zone 210

comprises perforations 204, 206 through the casing 602 (and supporting cement layer, if any) and into the target zone 210.

In the embodiment of Figure 6, the stimulation module 116 may comprise a hydraulic fracturing unit configured to fracture the target zone 210 and enhance the flow of the fluid 122 into the target zone 210. The stimulation module 116 may comprise an explosive device.

In one embodiment of Figure 6 when the stimulation module 116 comprises an explosive device, the system 100 may be configured such that the drilling unit 112 drills through the target zone 210, the stimulation module 116 stimulates the target zone 210 with an explosion, the completion unit 118 sets casing 602 across the target zone 210, cements the casing 602, and forms perforations 204, 206 through the casing 602. In the example, the stimulation module 116 may be further configured to stimulate the target zone 210 near the wellbore to connect the perforations 204, 206 to the stimulated target zone 210. The near wellbore stimulation may involve a hydraulic fracturing treatment, a matrix acid treatment, or the like to reconnect the perforations 204, 206 to the previously fractured target zone 210.

The production module 216 may flow the production fluid 126 directly up the annulus between the injection tubing 218 and the casing 602. In the embodiment of Figure 6, the production fluid 126 is flowed up a production tube 216 within the annulus between the injection tubing 218 and the casing 602.

Figure 7 is a schematic block diagram depicting one embodiment of heating a fluid 122 in accordance with the present invention. The system 100 may comprise a circulation unit (not shown) configured to circulate the fluid 122 through an offset well 702 near the production well 114. The offset well 702 may comprise a depleted zone 704, which may be a zone within an oil shale formation 212 which may already be depleted of production products, or kerogen. As used herein, offset indicates a well connected to a depleted zone 704 that is not the target zone 210 intended for production. The well connected to the target zone 210 may be called the producing well. The offset well may be an adjacent well to the producing well, a well completely across the field from the producing well, or a separate horizontal branch within the producing well, where the separate horizontal branch is in fluid communication with the depleted zone 704, but is fluidly isolated – except for the intended delivery of the heated fluid 124 from the injection unit 120 – from the target zone 210.

After circulation through the offset well, the fluid 122 may then be further heated in the system 100 or injected by the injection unit 120. The base temperature in the formation 704 is often much higher than the ambient surface temperature, and a significant savings in thermal

energy costs can be achieved through heating the fluid 122 according to the embodiment of Figure 7.

Figure 8A is a schematic block diagram depicting one embodiment of a first 802 and second 804 horizontal well segment in accordance with the present invention. The horizontal well segments 802, 804 share many features with the vertical well 114 descriptions of Figures 2 and 6, including the function of the stimulation module 116 and other features. Therefore, the description of Figure 8A should be read to be additive to those descriptions, and only to highlight a few differences that may be present in embodiments of the present invention that utilize one or more horizontal well segments.

The at least one fluid conduit 114 may comprise a first horizontal well segment 802 and a second horizontal well segment 804. The first horizontal well segment 802 may be in fluid communication with the top of the target zone 210, and the second horizontal well segment 804 may be in fluid communication with the bottom of the target zone 210. The system 100 may comprise an injection tube 218 positioned substantially at the bottom of the target zone 210, and a production tube 216 positioned substantially at the top of the target zone 210.

The system 100 may further include a second target zone 502. The system 100 may include a first isolation unit 806 and a second isolation unit 808 configured such that the injection tube 218 and production tubes 216 are fluidly isolated from the second production zone 502. The well 114 completion of Figure 8A may be an openhole completion or a cased completion wherein the casing 602 is perforated.

The first target zone 210 may comprise a horizontal width equivalent to the thickness (height) of the first target zone 210. Such parameters are desirable because the fluid 122 injected at the injection tube 218 into the first target zone 210 generally propagates as a normally distributed curve within the target zone 210, reaching a horizontal width approximately equal to the height of the target zone 210 by the time the fluid 122 propagates to the height of the target zone 210 (see Figure 10).

However, specific embodiments may vary considerably from this general guideline. For example, the horizontal length of the first and second horizontal segments 802, 804 may be 225 feet, and the height of the target zone 210 may be 100 feet. In such an example, splitting the oil shale formation 212 into two target zones 210, 502 of 112.5 feet each with none of the oil shale formation left completely untreated will yield better oil recovery than two target zones 210, 502 of 100 feet each, with 25 feet of the oil shale formation left untreated. In another example, the horizontal length of the first and second horizontal segments 802, 804 may be 200 feet, and the height of the target zone 210 may be 100 feet. For the purposes of the example, if the oil content

of the formation 212 is relatively high, and the price of oil is relatively high, the costs of completing and producing additional target zones within the formation 212 may be lower than the enhanced recovery by using shorter target zones. Therefore, splitting the oil shale formation 212 into three target zones 210, 502, (not pictured) axially along the horizontal segments 802, 804 may yield better economic recovery from the well 114 than two target zones 210, 502 at 100 feet each.

Where the target zone width is greater than the target zone height, the oil recovery will be lower, but the unit cost of production will be lower. Where the target zone width is lower than the target zone height, the oil recovery will be higher, but the unit cost of production will be higher. The selection of target zone 210, 502 lengths along the horizontal segments 802, 804 of the well is a similar exercise to determining the economic well spacing in embodiments using a vertical well 114, discussed later. These economic considerations are within the skill of one in the art to determine optimal target zone 210, 502 spacing based upon the production costs associated with a particular embodiment of the system 100, the oil content of the formation 212, and the disclosures herein, including the discussions referencing Figures 10A and 10B.

Figure 8B is a schematic block diagram depicting an alternate embodiment of a first and second horizontal well segment 802, 804 in accordance with the present invention. Figure 8B illustrates an embodiment where the first horizontal well segment 802 is associated with a first well 114, and the second horizontal well segment 804 is associated with a second well 810. The information relating to the embodiment of Figure 8A otherwise applies to the embodiment of Figure 8B, and is not included to avoid unnecessary repetition.

Figure 9 is a schematic block diagram depicting one embodiment of a first, second, and third horizontal well segment 802, 804, 902 in accordance with the present invention. The embodiment of Figure 9 may be used to develop two target zones 210, 502 utilizing horizontal well segments 802, 804, 902 wherein the target zones 210, 502 are aligned vertically, i.e. one target zone is above the other. In the embodiment of Figure 9, the drilling unit 112 may be further configured to drill a third horizontal segment 902 fluidly coupled to the top of the second target zone 502.

The first horizontal segment 802 may be in fluid communication with the bottom of the second target zone 502. The stimulation module 116 may stimulate the second target zone 502. The completion unit 118 may position the injection tube 218 substantially at the bottom of the second target zone 502. The injection unit 120 may inject the fluid 122 into the second target zone 502. The thermal delivery unit 124 may heat the fluid 122 such that the heated fluid entrains in-situ kerogen from the second target zone 502 to generate the production fluid 126.

The isolation unit (not shown) may be further configured to isolate the fluid conduit 114 from the first target zone 210, for example by placing a cement plug and/or a bridge plug in the second horizontal segment 804. The production module 216 may be configured to produce the production fluid 126.

The first target zone 210 and second target zone 502 may both be produced in a similar manner to the embodiment shown and described in relation to Figure 8A, wherein the injection tube 218 is positioned substantially at the bottom of the first target zone 210 and/or second target zone 502, and a production tube 216, or flow area within a casing 602 annulus, receives the fluid 122 substantially at the top of the first target zone 210 and/or second target zone 502. Each target zone 210, 502 may be divided into additional axially oriented target zones as illustrated in Figure 8A. In a further embodiment, the system 100 may be configured to produce the second target zone 502 upon the substantial depletion of the first target zone 210.

One of skill in the art will recognize that the proper combination of injection units 220, injection tubes 218, and production modules 216 would allow the simultaneous production of multiple target zones 210, 502 even within the same well 114. Such simultaneous production is merely practicing multiple embodiments of the invention simultaneously, and is considered within the scope of the invention.

Figure 10A is an illustration of a well spacing 1002 in accordance with the present invention. Figure 10A illustrates a first well 114 and a second well 1014 that may comprise adjacent wells within an oil shale field. The wells in the embodiment of Figure 10A comprise a spacing 1002, or horizontal offset, of 200 feet, and a target zone thickness (TZT) 1004 of 100 feet. The injected gas 122 propagates through the formation 212 in a curve 1006, 1008 that approximates a normal distribution where the one-half width of each curve 1006, 1008 at the top of the target zone 210 is approximately equal to the TZT 1004.

When the fluid 122 is injected at the proper pressure, the free water (if any) within the propagation curve 1006, 1008 inside the target zone 210 is displaced by the injected fluid 122, and heating of the target zone 210 can be achieved. The area above the injected gas 122 propagation curve 1006, 1008 will be the primary area wherein kerogen is stripped from the target zone 210 and where the associated well 114, 1014 will produce from. One example of a target zone 210 is overlaid on the propagation curve 1006 in Figure 10A to illustrate how the target zone 210 and propagation curve 1006 may relate to each other.

In the embodiment of Figure 10A, an unproduced area 1010 between the first well 114 and the second well 1014 is created due to the shape of the gas propagation 1006, 1008 through the formation 212. However, the spacing 1002 of the embodiment of Figure 10A ensures that

little or no formation 212 volume is produced by more than one well, because there is little or no overlap between the first propagation curve 1006 and the second propagation curve 1008. The spacing 1002 of Figure 10A will optimizing the drilling and production costs per unit of oil produced. The spacing 1002 of Figure 10A may be described as: S = 2.0 * TZT, where S equals the well spacing. In one embodiment, the spacing 1002 of Figure 10A is appropriate where drilling and production costs dominate the economics of the system 100.

Figure 10B is an illustration of an alternate well spacing 1002 in accordance with the present invention. Figure 10B illustrates a first well 114 and a second well 1014 that may comprise adjacent wells within an oil shale field. The wells in the embodiment of Figure 10B comprise a spacing 1002 of 50 feet, and a TZT 1004 of 100 feet.

In the embodiment of Figure 10B, an unproduced area 1010 between the first well 114 and the second well 1014 is created due to the shape of the gas propagation 1006, 1008 through the formation 212. The unproduced area 1010 for the embodiment of Figure 10B is clearly small relative to the embodiment of Figure 10A. A redundantly produced area 1012 between the first well 114 and the second well 1014 is created due to the shape of the gas propagation 1006, 1008 through the formation 212 and the close proximity of the wells 114, 1014. The embodiment of Figure 10B approximates the maximum recovery from the formation 212, as bringing the wells 114, 1014 closer would yield little reduction in the unproduced area 1010 while significantly increasing the redundantly produced area 1012. The spacing of the embodiment of Figure 10B may be described as: S = 0.5 * TZT. In one embodiment, the spacing of Figure 10B is appropriate where the oil content of the formation 212 is high, and the price of oil dominates the economics of the system 100.

It is within the skill of one in the art to determine an intermediate well spacing between the embodiment of Figure 10A and Figure 10B based on the specific economic factors for a given embodiment of the invention. Further, it is within the skill of one in the art to analogize the fluid propagation shape 1006, 1008 to a horizontal well (refer to Figures 8A, 8B, 9) to determine an optimal target zone 210, 502 size selection for a given embodiment of the invention. In some situations, a well spacing 1002 closer than the embodiment of Figure 10B may be appropriate based on the specific economic factors of a given embodiment of the invention, and such spacing is contemplated within the scope of the invention.

Figure 11 is an illustration of a thermodynamic equilibrium chart for heavy hydrocarbons in the absence of excess hydrogen. As indicated by Figure 11, heavier hydrocarbons, above 30 carbons per molecule, are favored in the absence of excess hydrogen. Figure 11 illustrates that a

treatment module 128 operating in the absence of excess hydrogen is not expected to crack most formation kerogen compositions into smaller hydrocarbon molecules.

Figure 12 is an illustration of a thermodynamic equilibrium chart for heavy hydrocarbons in the presence of excess hydrogen. As indicated by Figure 12, lighter hydrocarbons, around 10 carbons per molecule, are favored in the presence of excess hydrogen. Significant improvements in light hydrocarbon yield are achieved at all temperatures above about 65 degrees C for the hydrocarbon mix illustrated in Figure 12, indicating that excess hydrocarbon is sufficient to favor light hydrocarbons at all reasonable operating temperatures. However, the reaction kinetics of cracking a heavy hydrocarbon indicate that temperatures for the catalytic reactor 302 need to be much higher than the minimum required to favor light hydrocarbons thermodynamically.

The exact temperatures required for an economically acceptable reaction speed in hydrocarbon cracking depend upon the composition of the kerogen in the production fluid 126, the selected catalyst, the physical makeup of the catalytic reactor (size of the reactor, catalyst loading, catalyst bead pore size), and the flow rates of the production fluid 126. These determinations are within the skill of on in the art for selecting a target temperature. A temperature requirement for a typical system 100 will be greater than 350 degrees C. As with almost all catalytic systems, some straightforward testing, within the skill of one in the art, is required to determine a target temperature for a specific production fluid 126 composition.

The schematic flow chart diagrams herein are generally set forth as logical flow chart diagrams. As such, the depicted order and labeled steps are indicative of one embodiment of the presented method. Other steps and methods may be conceived that are equivalent in function, logic, or effect to one or more steps, or portions thereof, of the illustrated method. Additionally, the format and symbols employed are provided to explain the logical steps of the method and are understood not to limit the scope of the method. Although various arrow types and line types may be employed in the flow chart diagrams, they are understood not to limit the scope of the corresponding method. Indeed, some arrows or other connectors may be used to indicate only the logical flow of the method. For instance, an arrow may indicate a waiting or monitoring period of unspecified duration between enumerated steps of the depicted method. Additionally, the order in which a particular method occurs may or may not strictly adhere to the order of the corresponding steps shown.

Figure 13 is a schematic flow diagram of a method 1300 for extracting oil from oil shale in accordance with the present invention. The method 1300 may begin with a drilling unit 112 drilling 1302 at least one fluid conduit to a top of a target zone 210 and a bottom of the target zone 210 of an oil shale formation 212. The stimulating module 116 may stimulate 1304 the

target zone 210. A completion unit 118 may position 1306 an injection tube 218 substantially at the bottom of the target zone 210, and a position 1308 a production tube 216 substantially at the top of the target zone 210.

The method 1300 may include an injection unit 120 injecting 1310 fluid 122 into the target zone 210. Injecting 1310 the fluid 122 into the target zone 210 may include injecting the fluid 122 at a pressure greater than the formation fluid pressure, and lower than the formation fracture pressure, such that the fluid 122 displaces free water within the formation.

A thermal delivery unit 124 may heat 132 the fluid 122 with a downhole burner 402 to generate a production fluid 126 with entrained kerogen. The production module 216 may produce 1314 the production fluid 126. The method 1300 may further include a treatment module 128 heating 1316 the production fluid 126 to a target temperature, and treating 1318 the production fluid 126 in a catalytic reactor 302 to reduce the average molecular weight of the entrained kerogen. Treating 1318 the production fluid 126 may further include adding natural gas from a natural gas storage facility 110 to the production fluid 126 such that a minimum estimated amount of hydrogen is available for reaction within the catalytic reactor 302.

Figure 14A is a schematic flow diagram of a method 1400 for extracting oil from an oil shale comprising a first and second target zone 210, 502 in accordance with the present invention. The method 1400 may begin with a drilling unit 112 drilling 1402 at least one fluid conduit to a top and a bottom of a target zone 210. A completion unit 118 may set 1404 a production casing 602 across the target zone 210, and perforate 1406 the casing 602 substantially at the top and at the bottom of the target zone 210.

The stimulation module 116 may stimulate 1408 the target zone 210. A completion unit 118 may position 1410 an injection tube 218 in the casing 602 substantially at the bottom of the target zone 210. A circulation unit (not shown) may circulate 1412 the fluid 122 through an offset well 702 with a depleted zone 704. A thermal delivery unit 124 may heat 1414 the fluid 122 with a solar concentrator 136, and a gas burner 134.

The method 1400 may include an injection unit 120 injecting 1416 the fluid 122 into the target zone 210, where the fluid may heat and entrain kerogen within the target zone 210 to generate a production fluid 126. A production tube 116 may produce 1418 the production fluid 126.

Referring to Figure 14B, the method 1400 may continue with a stimulation module 116 stimulating 1420 a second target zone 502. An isolation unit (not shown) may isolate the first target zone 210. A completion unit 118 may position 1424 the injection tube 118 substantially at the bottom of the second target zone 502. A circulation unit (not shown) may circulate 1426 the

fluid 122 through an offset well 702 with a depleted zone 704. A thermal delivery unit 124 may heat 1428 the fluid 122 with a solar concentrator 136, and a gas burner 134. An injection unit 120 may inject 1430 the fluid 122 into the second target zone 502 where the fluid 122 may heat and entrain kerogen within the second target zone 502 to generate a production fluid 126. The production tube 116 may produce 1432 the production fluid 126.

Figure 15A is a schematic flow diagram of a method 1500 for extracting oil from an oil shale. The method 1500 may begin with a drilling unit 112 drilling 1502 a first horizontal well segment 802 in fluid communication with the top of a target zone 210, and a second horizontal well segment 804 in fluid communication with the bottom of the target zone 210. The method 1500 may include a stimulation module 116 stimulating 1504 the target zone 210, and a completion unit 118 positioning 1506 an injection tube 218 substantially at the bottom of the target zone 210.

The method 1500 may include an injection unit 120 injecting 1508 fluid 122 into the target zone 210, and a thermal delivery unit 124 heating 1510 the fluid 122 such that the heated fluid 122 entrains kerogen to generate a production fluid 126. The method 1500 may include a production tube 216 producing 1512 the production fluid 126. The method 1500 may continue with the drilling unit 112 drilling 1514 a third horizontal well segment 902 in fluid communication with a top of a second target zone502, where the first horizontal well segment 802 is in fluid communication with the bottom of the second target zone 502.

Referring to Figure 15B, the stimulation module 116 may stimulate 1516 the second target zone 502. The completion unit 118 may position 1518 an injection tube 218 substantially at the bottom of the second target zone 502. The method 1500 may include an isolation unit (not shown) isolating 1520 the fluid conduit in communication with the first target zone 804 from the fluid conduits in communication with the second target zone 802, 902.

The method 1500 may include the injection unit 120 injecting 1508 fluid 122 into the second target zone 502, and a thermal delivery unit 124 heating 1510 the fluid 122 such that the heated fluid 122 entrains kerogen to generate a production fluid 126. The method 1500 may include a production tube 216 producing 1512 the production fluid 126.

From the foregoing discussion, it is clear that the invention provides a system, method, and apparatus for in-situ extraction of oil from an oil shale. The invention overcomes previous limitations in the art by providing an energy efficient process utilizing inexpensive completion techniques to produce the oil in an environmentally sound manner.

The present invention may be embodied in other specific forms without departing from its spirit or essential characteristics. The described embodiments are to be considered in all

respects only as illustrative and not restrictive. The scope of the invention is, therefore, indicated by the appended claims rather than by the foregoing description. All changes which come within the meaning and range of equivalency of the claims are to be embraced within their scope.

CLAIMS

1. An apparatus for extracting oil from oil shale, the apparatus comprising:
   a drilling unit configured to drill at least one fluid conduit to a top of a target zone and a bottom of the target zone of an oil shale formation;
   a stimulation module configured to stimulate the target zone;
   a completion unit configured to position an injection tube substantially at the bottom of the target zone;
   an injection unit configured to inject a fluid into the target zone;
   a thermal delivery unit configured to heat the fluid such that the heated fluid entrains in-situ kerogen to generate a production fluid; and
   a production module to produce the production fluid.

2. The apparatus of Claim 1, wherein the injection unit is further configured to inject the fluid into the target zone such that the fluid displaces free water within the target zone.

3. The apparatus of Claim 1, wherein the thermal delivery unit is further configured to heat the fluid such that the fluid temperature exceeds 300 degrees C at the bottom of the target zone.

4. The apparatus of Claim 1, wherein the thermal delivery unit is further configured to heat the fluid such that the fluid temperature exceeds 400 degrees C at the bottom of the target zone.

5. The apparatus of Claim 1, wherein the thermal delivery unit is further configured to heat the fluid at the surface, and wherein the injection tube comprises a vacuum insulated tube.

6. The apparatus of Claim 5, wherein heating the fluid at the surface comprises heating the fluid with at least one solar concentrator.

7. The apparatus of Claim 5, wherein heating the fluid at the surface comprises heating the fluid with a natural gas burner.

8. The apparatus of Claim 1, wherein the thermal delivery unit comprises a downhole burner configured to heat the fluid within the at least one fluid conduit.

9. The apparatus of Claim 1, further comprising a treatment module configured to heat the production fluid to a target temperature and to react the production fluid in a catalytic reactor.

10. The apparatus of Claim 9, wherein the target temperature comprises a temperature greater than 350 degrees Celsius.

11. The apparatus of Claim 1 wherein the drilling unit comprises a coiled tubing drilling unit.

12. The apparatus of Claim 1, wherein the stimulation module comprises an explosive.

13. The apparatus of Claim 1, wherein the production module comprises a production tube positioned substantially at the top of the target zone.

14. The apparatus of Claim 1, wherein:
the target zone comprises a first target zone;
wherein the stimulation module is further configured to stimulate a second target zone;
wherein the completion unit is further configured to position the injection tube substantially at the bottom of the second target zone;
the apparatus further comprising an isolation unit configured to isolate the at least one fluid conduit from the first target zone;
wherein the injection unit is further configured to inject the fluid into the second target zone; and
wherein the thermal delivery unit is further configured to heat the fluid such that energy of the heated fluid entrains in-situ kerogen within the second target zone to generate the production fluid.

15. The apparatus of Claim 14, wherein the isolation unit comprises one of a bridge plug and a cement plug.

16. A method for extracting oil from oil shale, the method comprising:
drilling at least one fluid conduit to a top of a target zone and a bottom of the target zone of an oil shale formation;
stimulating the target zone;
positioning an injection tube substantially at the bottom of the target zone;
injecting a fluid into the target zone;

heating the fluid such that the heated fluid entrains in-situ kerogen to generate a production fluid; and

producing the production fluid.

17. The method of Claim 16, wherein injecting fluid into the target zone further comprises injecting the fluid into the target zone at a pressure higher than a formation fluid pressure and lower than a formation fracture pressure, such that the fluid displaces free water within the target zone.

18. The method of Claim 16, further comprising heating the production fluid to a target temperature, and treating the production fluid in a catalytic reactor to reduce the average molecular weight of the entrained kerogen.

19. The method of Claim 18, further comprising adding natural gas to the production fluid such that a minimal amount of hydrogen is available for reaction within the catalytic reactor.

20. The method of Claim 16, further comprising positioning a production tube substantially at the top of the target zone, and wherein producing the production fluid comprises flowing the production fluid up the production tubing.

21. The method of Claim 16, further comprising setting a production casing through the oil shale formation, perforating the production casing substantially near the bottom of the target zone, perforating the production casing substantially near the top of the target zone, wherein positioning the injection tube further comprises positioning the injection tube within the production casing, and wherein producing the production fluid comprises flowing the production fluid up the annulus formed between the production casing and the injection tubing.

22. The method of Claim 21, wherein flowing the production fluid up the annulus formed by the casing and the injection tube comprises flowing the product up a production tube within the annulus.

23. The method of Claim 16, wherein the fluid comprises natural gas.

24. The method of Claim 23, wherein heating the fluid comprises at least one member selected from the group consisting of heating the fluid with a solar concentrator, and heating the fluid with a gas burner configured to burn a portion of the production fluid.

25. The method of Claim 23, wherein heating the fluid comprises circulating the fluid through a substantially depleted zone in an offset well, the substantially depleted zone comprising a shale formation substantially depleted of kerogen.

26. The method of Claim 16, wherein the fluid comprises at least one member selected from the group consisting of methane, ethane, propane, butane, hydrocarbon gas, hydrogen, carbon monoxide, nitrogen, helium, argon, and neon.

27. The method of Claim 16, wherein heating the fluid comprises heating the fluid with a downhole burner within the at least one fluid conduit.

28. The method of Claim 16, wherein drilling at least one fluid conduit to a top of a target zone and a bottom of the target zone of an oil shale formation comprises drilling a vertical well through the oil shale formation, and wherein the target zone comprises a target zone thickness (TZT).

29. The method of Claim 28, wherein the TZT comprises a thickness between 25 feet and 100 feet.

30. The method of Claim 28, further comprising drilling a plurality of vertical wells through the oil shale formation, wherein each of the plurality of vertical wells is spaced at a distance between about 0.5 times the TZT and about 2.0 times the TZT.

31. The method of Claim 28, wherein the target zone comprises a first target zone, the method further comprising stimulating a second target zone, positioning the injection tube substantially at the bottom of the second target zone, isolating the at least one fluid conduit from the first target zone, injecting the fluid into the second target zone, heating the fluid such that the heated fluid entrains in-situ kerogen within the second target zone to generate a production fluid, and producing the production fluid.

32. The method of Claim 16, wherein drilling at least one fluid conduit to a top of a target zone and a bottom of the target zone of an oil shale formation comprises drilling a first horizontal well segment in fluid communication with the top portion of the target zone,

and drilling a second horizontal well segment in fluid communication with the bottom portion of the target zone.

33. The method of Claim 32, wherein the target zone comprises a horizontal width equal to the height of the target zone.

34. The method of Claim 32, wherein the target zone comprises a first target zone, further comprising drilling a third horizontal well segment in fluid communication with the top portion of a second target zone, wherein the first horizontal well segment is in fluid communication with a bottom portion of the second target zone, the method further comprising stimulating the second target zone, positioning the injection tube substantially at the bottom of the second target zone, isolating the at least one fluid conduit from the first target zone, injecting the fluid into the second target zone, heating the fluid such that the heated fluid entrains in-situ kerogen within the second target zone to generate the production fluid, and producing the production fluid.

35. A system for in-situ extraction of oil from oil shale, the system comprising:
a three-phase separator configured to separate a production fluid into oil, water, and natural gas;
fluid coupling configured to deliver separated water to a water disposal system, to deliver separated oil to an oil storage facility, and to deliver separated natural gas to a natural gas storage facility;
a drilling unit configured to drill at least one fluid conduit to a top of a target zone and a bottom of the target zone of an oil shale formation;
a stimulation module configured to stimulate the target zone;
a completion unit configured to position an injection tube substantially at the bottom of the target zone;
an injection unit configure to inject a fluid into the target zone;
a thermal delivery unit configured to heat the fluid such that the heated fluid entrains in-situ kerogen to generate a product fluid;
a production module to produce the production fluid;
a treatment module configured to heat the production fluid to a target temperature and to react the production fluid in a catalytic reactor; and
a condensing module configured to cool the reacted production fluid and to deliver the reacted production fluid to the three-phase separator.

36. The system of Claim 35, further comprising an oil heater configured to receive heat from a solar concentrator and to receive heat from a natural gas burner, wherein the thermal delivery unit is further configured to heat the fluid using heat from the oil heater, and wherein the injection tube comprises a vacuum insulated tube.

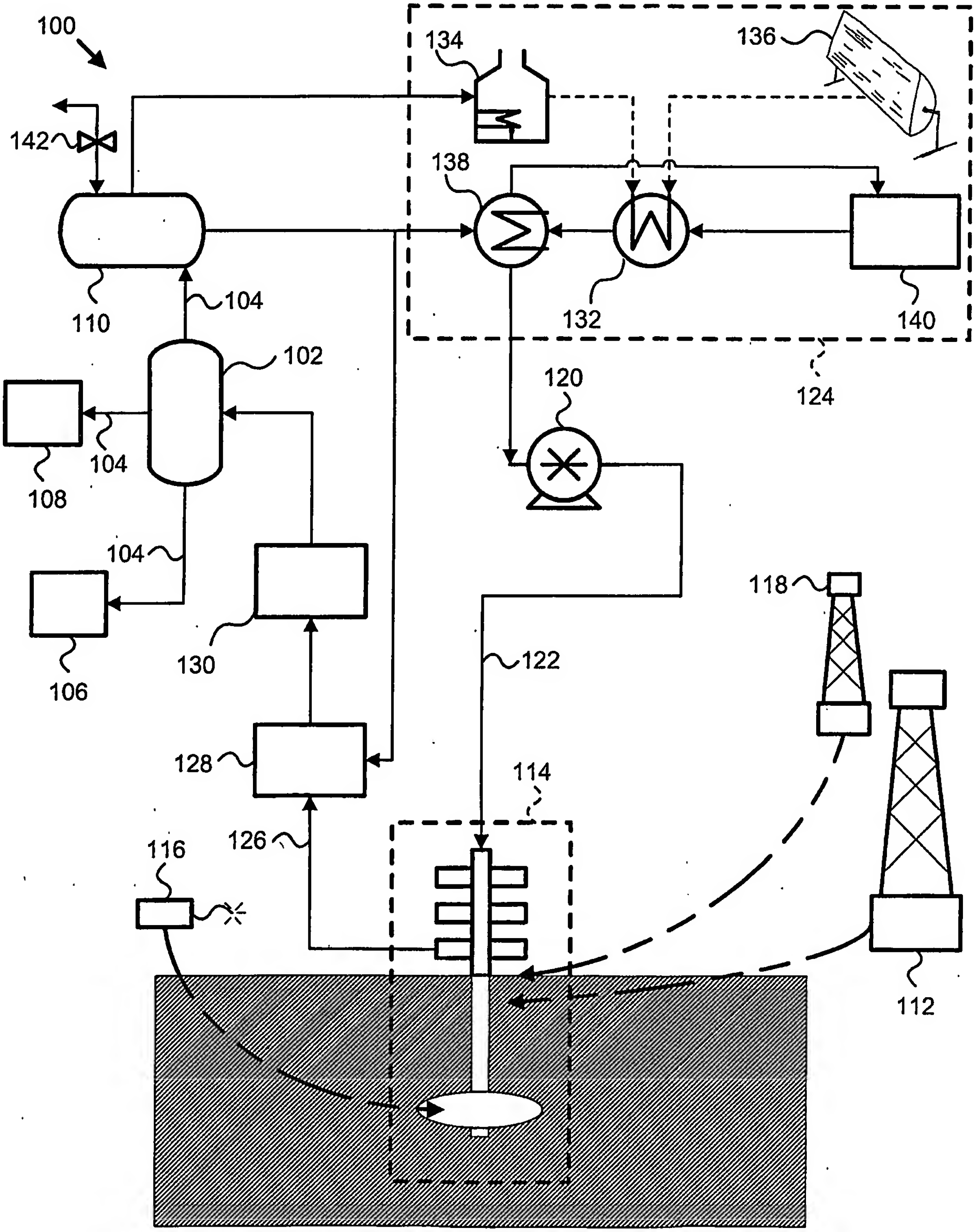
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Fig. 1

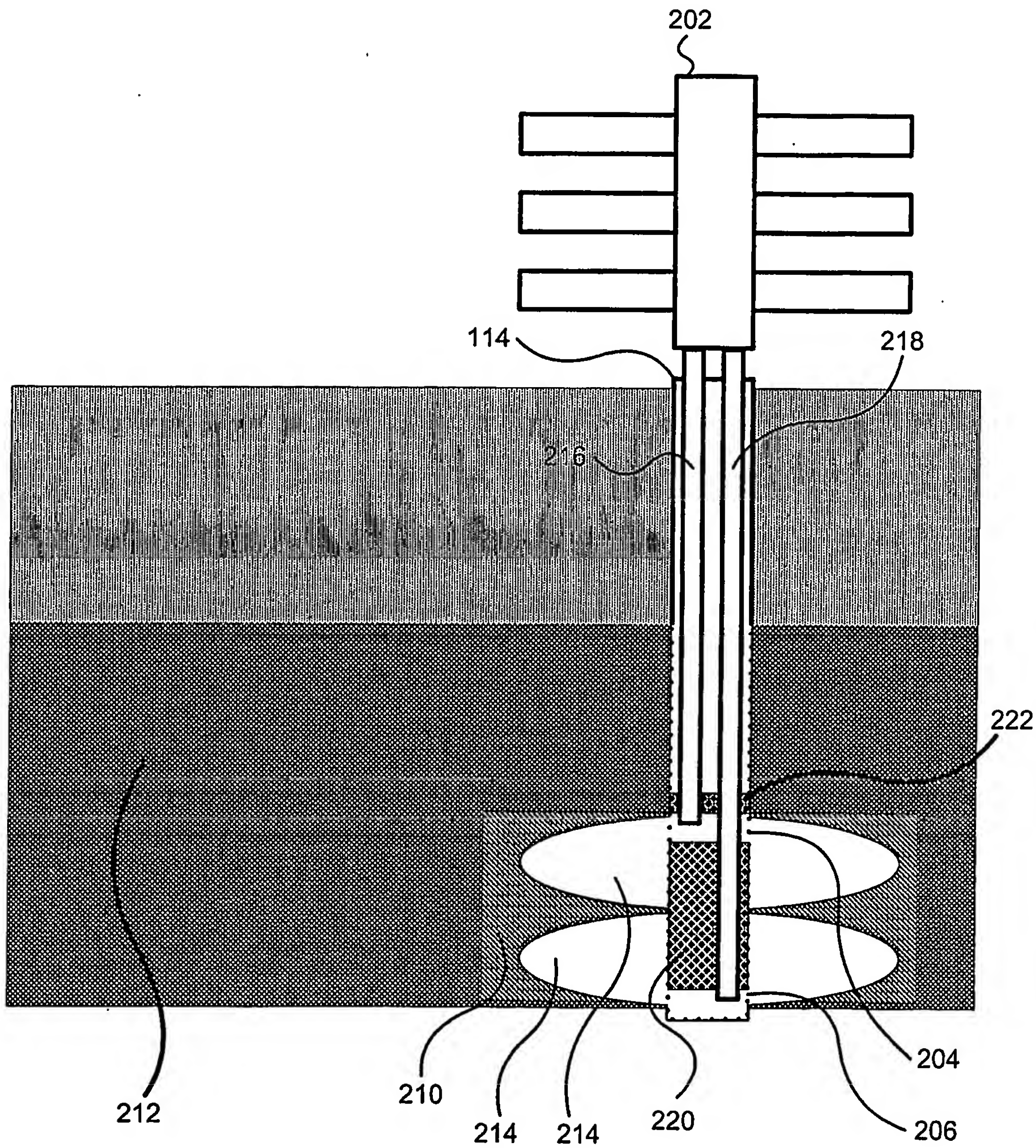

Fig. 2

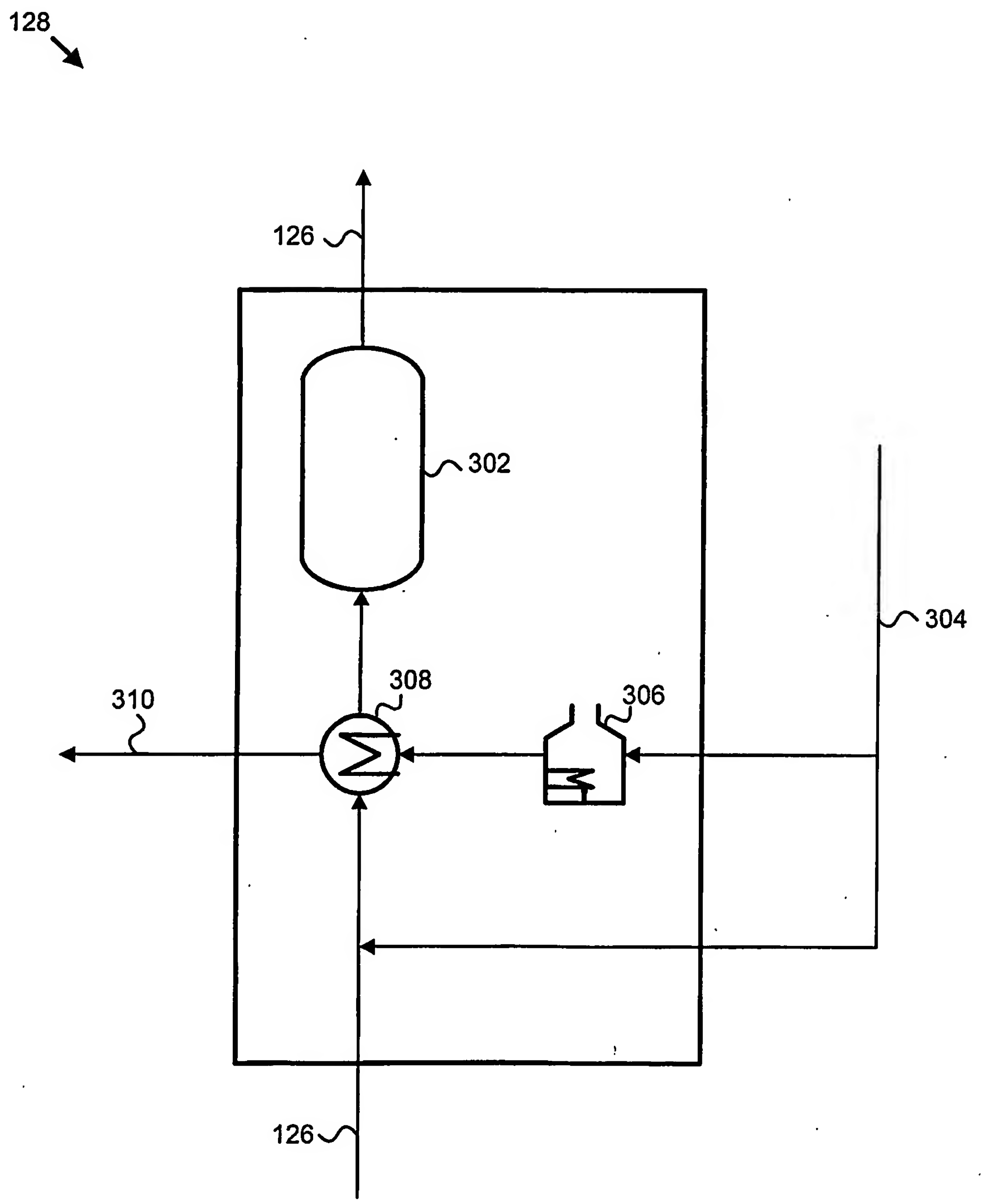

Fig. 3

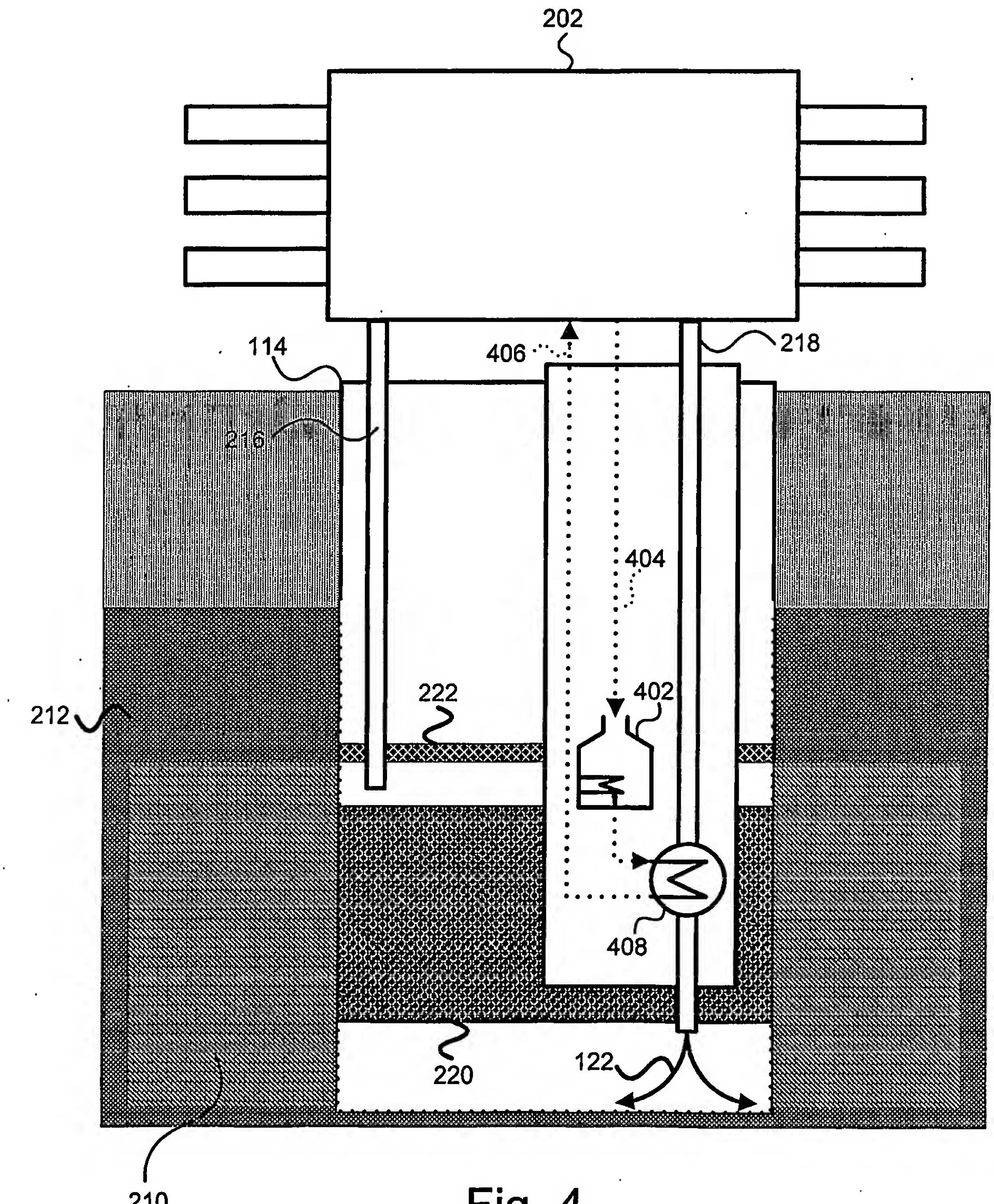

Fig. 4

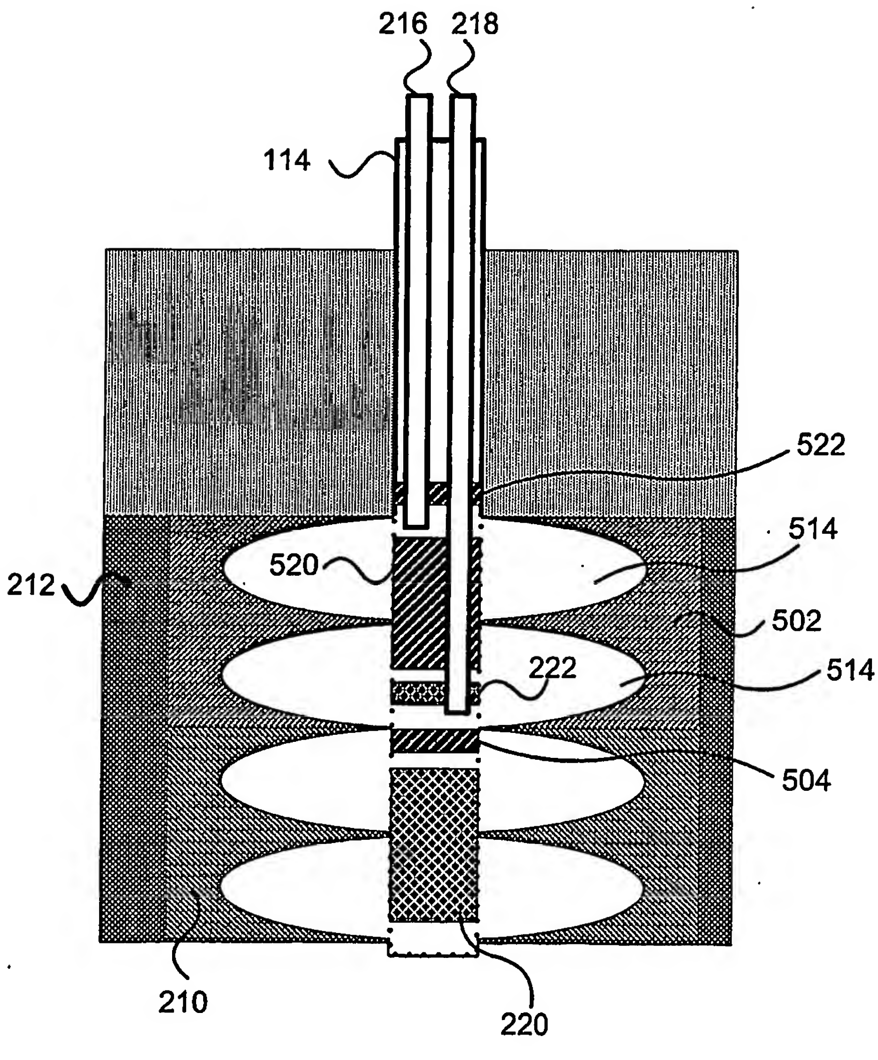

Fig. 5

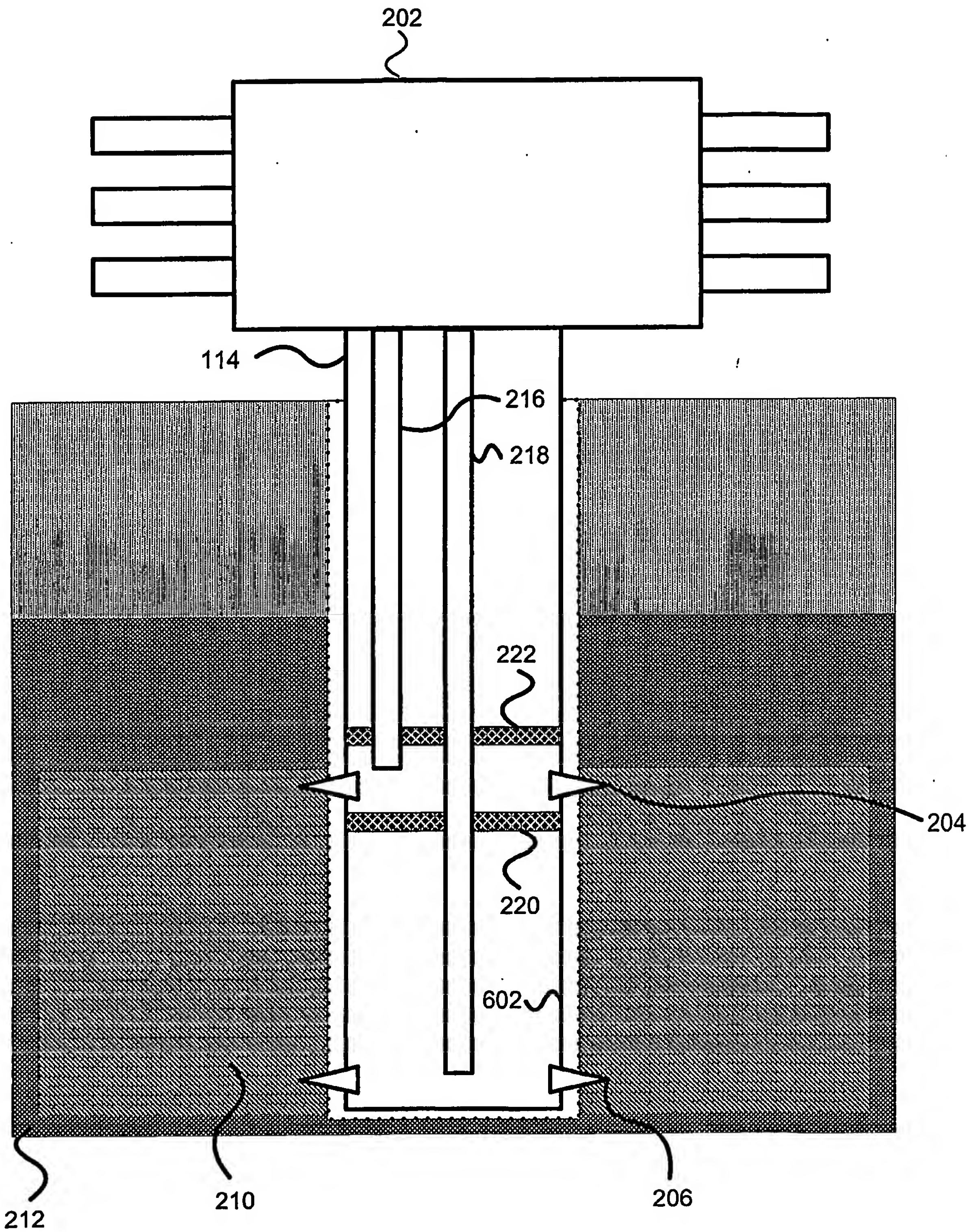

Fig. 6

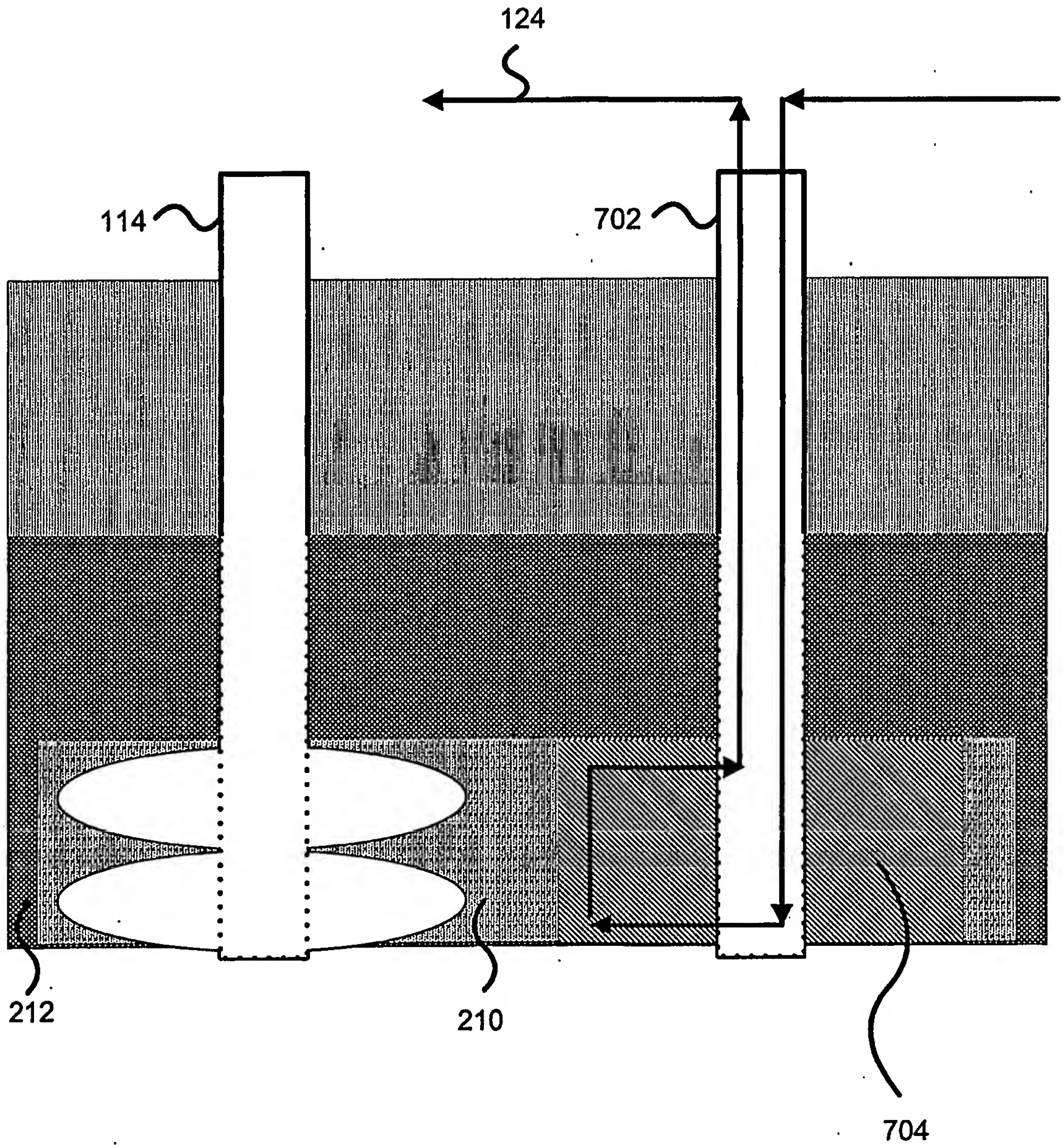

Fig. 7

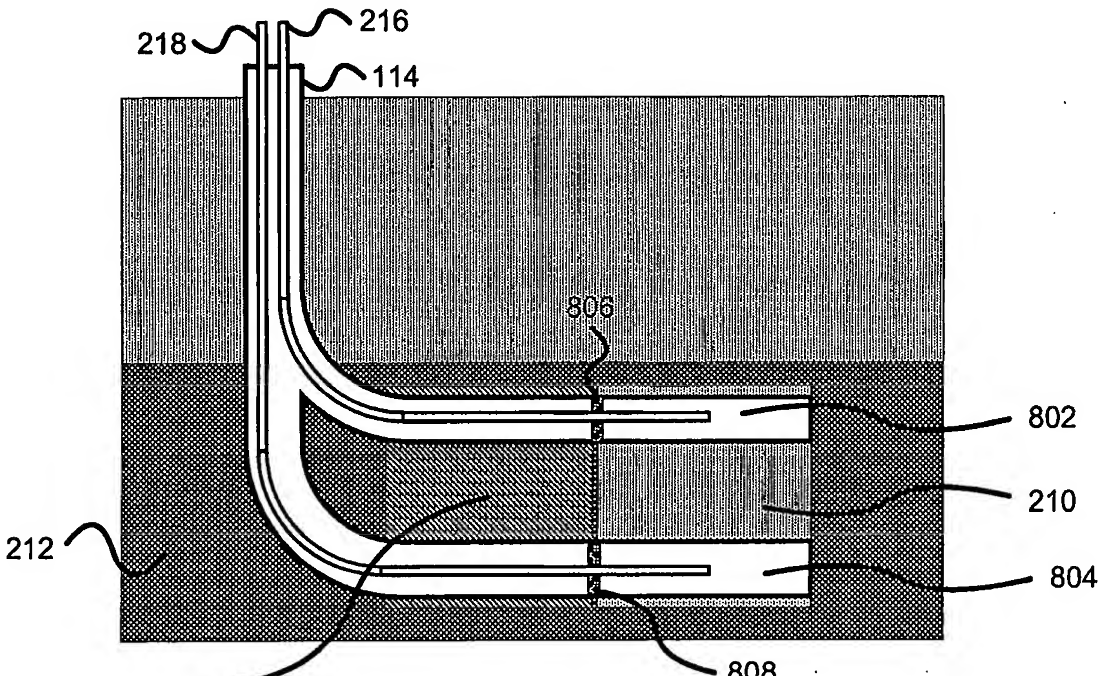

Fig. 8A

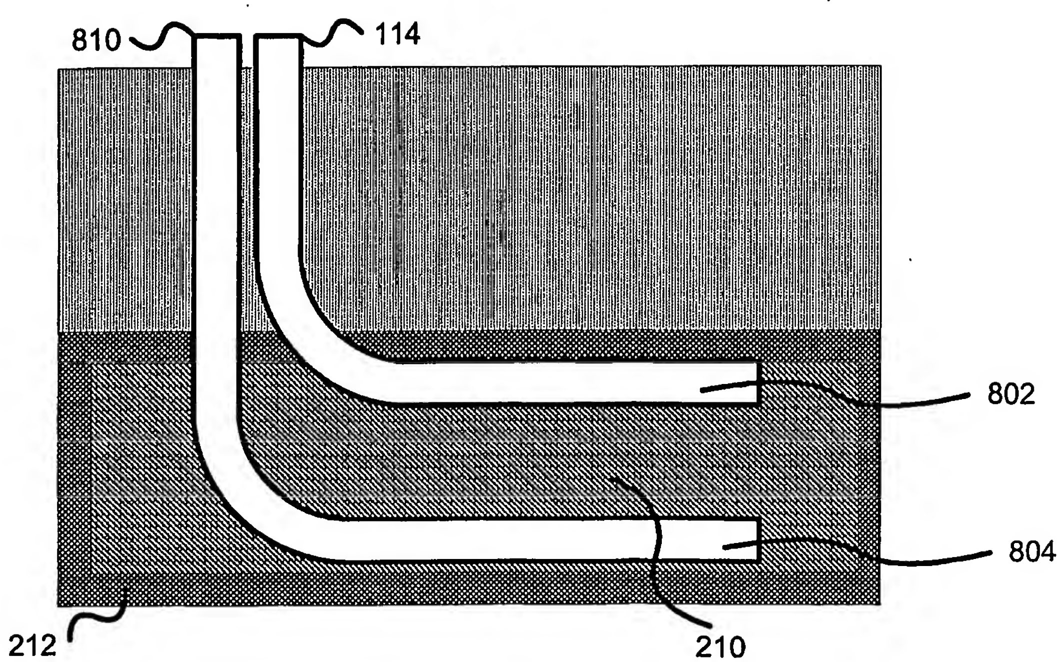

Fig. 8B

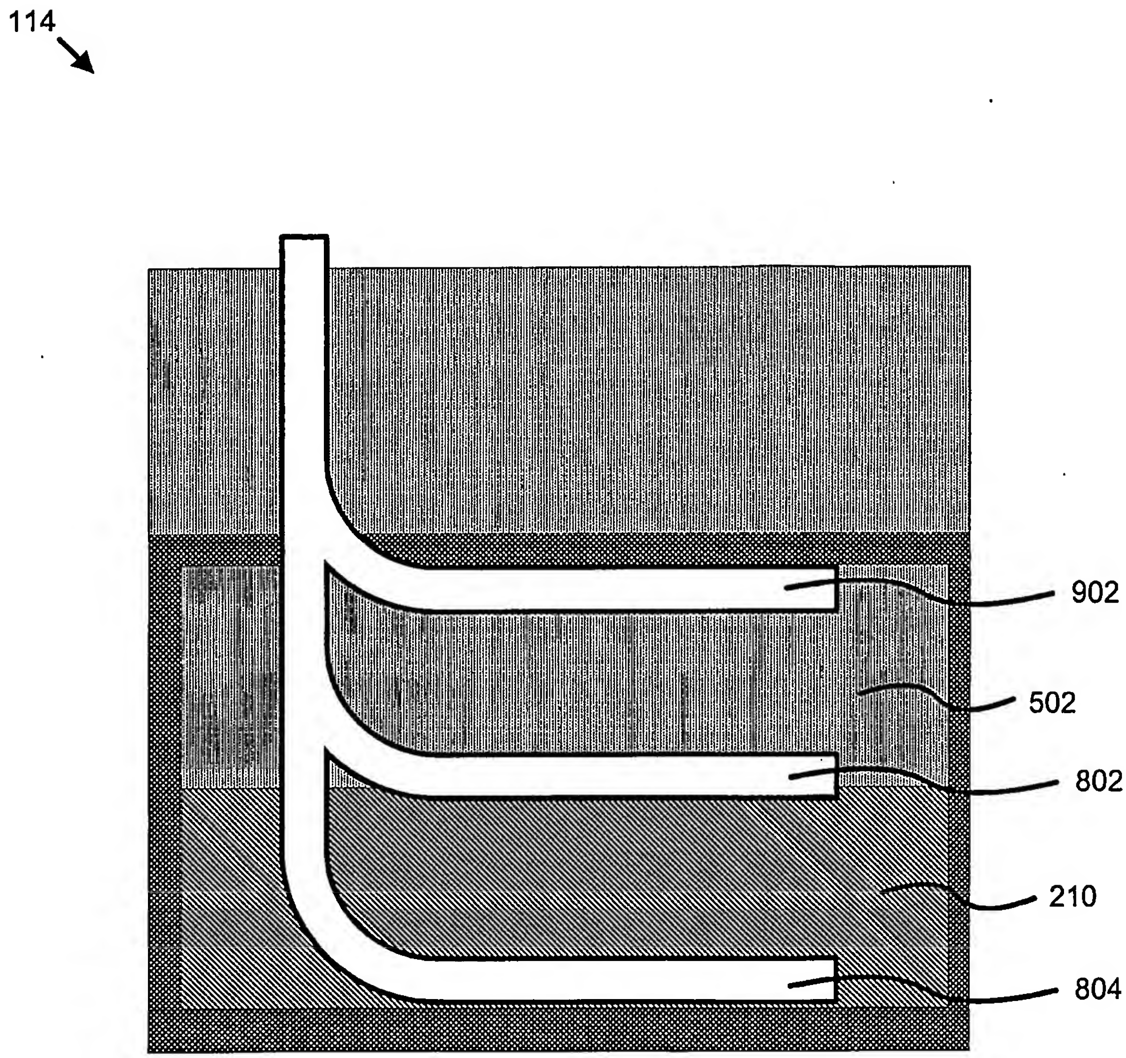

Fig. 9

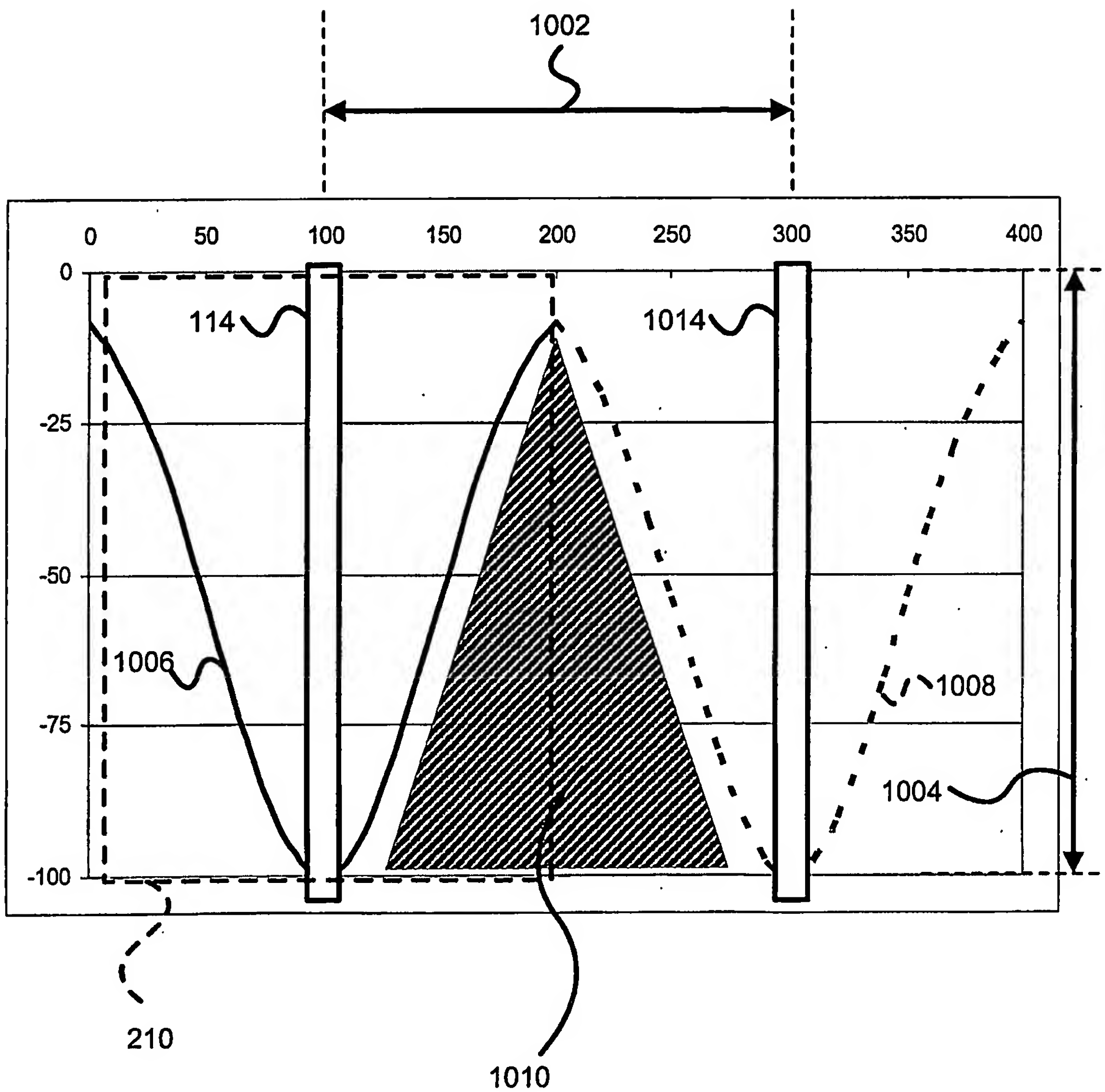
1002
0
50
100
150
200
250
300
350
400
0
-25
-50
-75
-100
114
1014
1006
1008
1004
210
1010

Fig. 10A

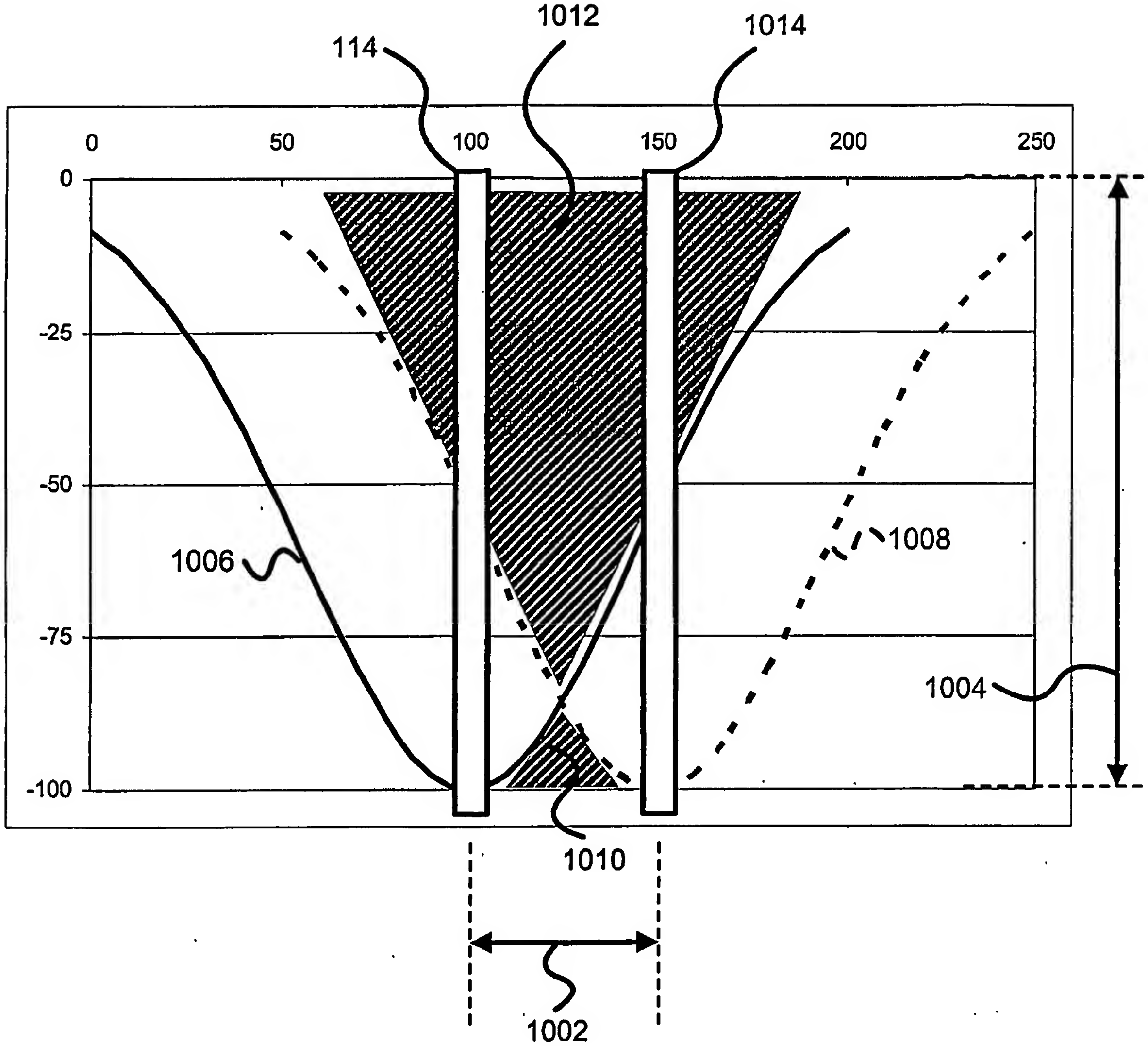
1012
114
1014
0
50
100
150
200
250
0
-25
-50
-75
-100
1006
1008
1004
1010
1002

Fig. 10B

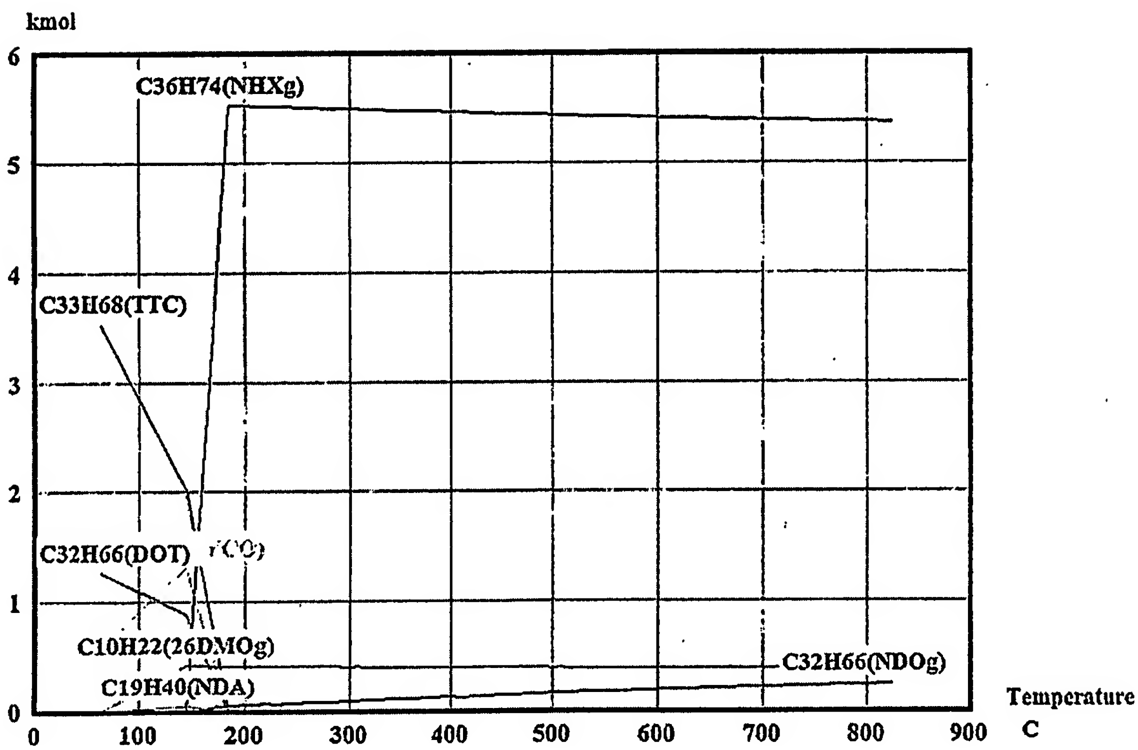
kmol
6
5
4
3
2
1
0
C36H74(NHXg)
C33H68(TTC)
C32H66(DOT)
C10H22(26DMOg)
C19H40(NDA)
C32H66(NDOg)
0
100
200
300
400
500
600
700
800
900
Temperature
C

Fig. 11

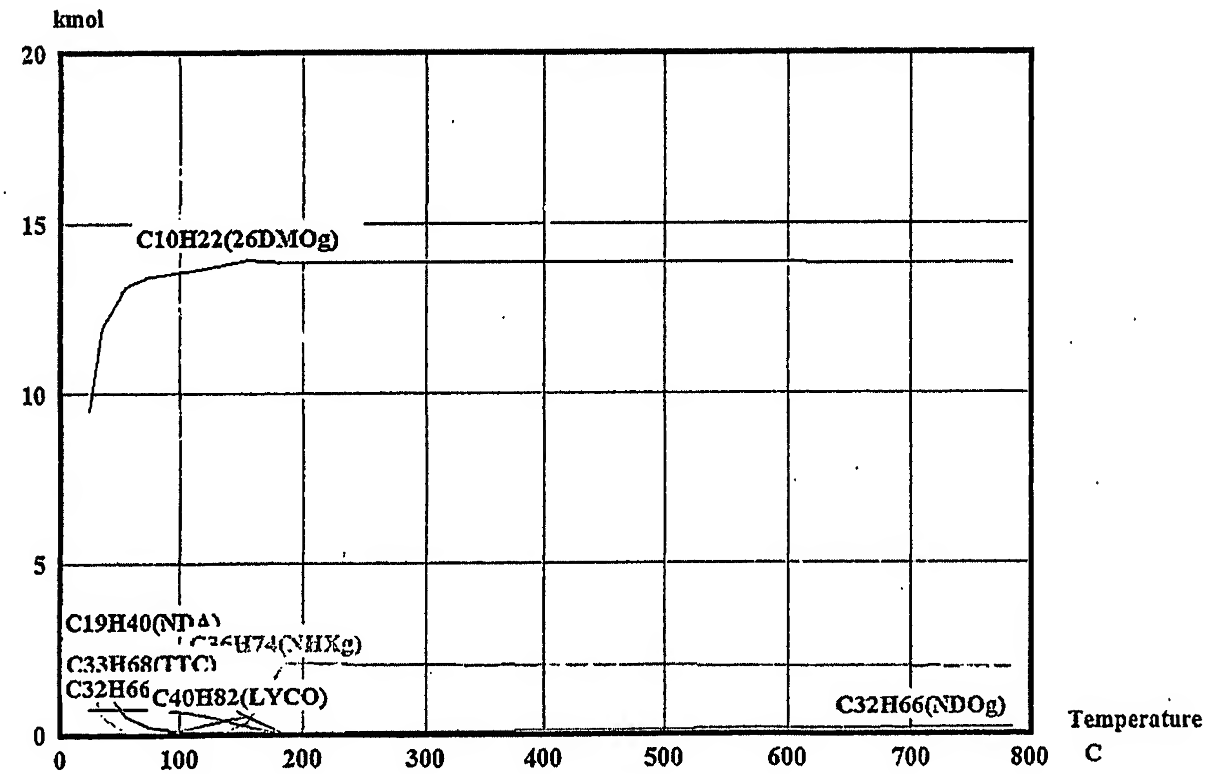
kmol
20
15
10
5
0
C10H22(26DMOg)
C19H40(NDA)
C36H74(NHXg)
C33H68(TTC)
C32H66
C40H82(LYCO)
C32H66(NDOg)
0
100
200
300
400
500
600
700
800
Temperature
C

Fig. 12

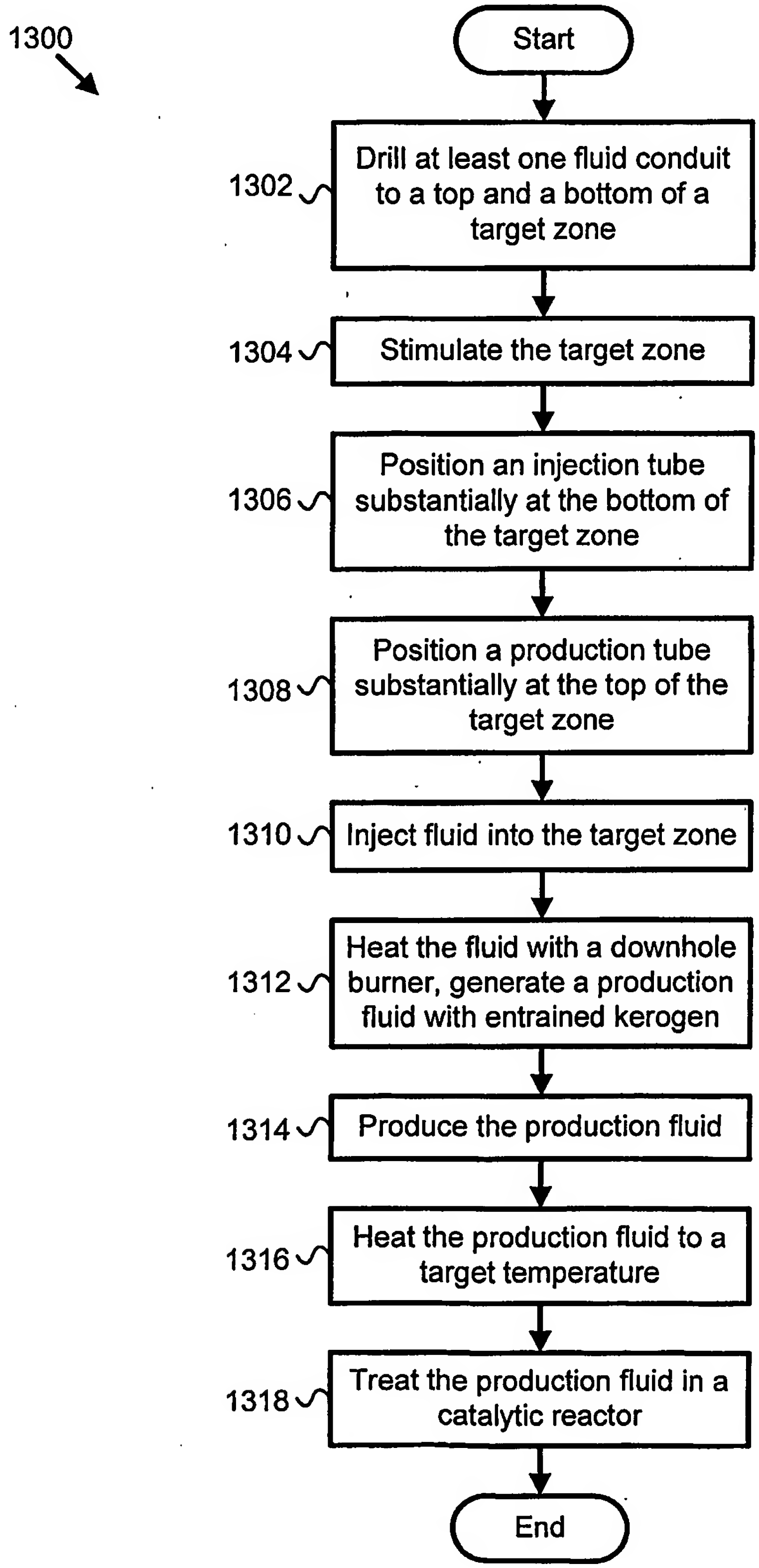
1300
Start
1302
Drill at least one fluid conduit to a top and a bottom of a target zone
1304
Stimulate the target zone
1306
Position an injection tube substantially at the bottom of the target zone
1308
Position a production tube substantially at the top of the target zone
1310
Inject fluid into the target zone
1312
Heat the fluid with a downhole burner, generate a production fluid with entrained kerogen
1314
Produce the production fluid
1316
Heat the production fluid to a target temperature
1318
Treat the production fluid in a catalytic reactor
End

Fig. 13

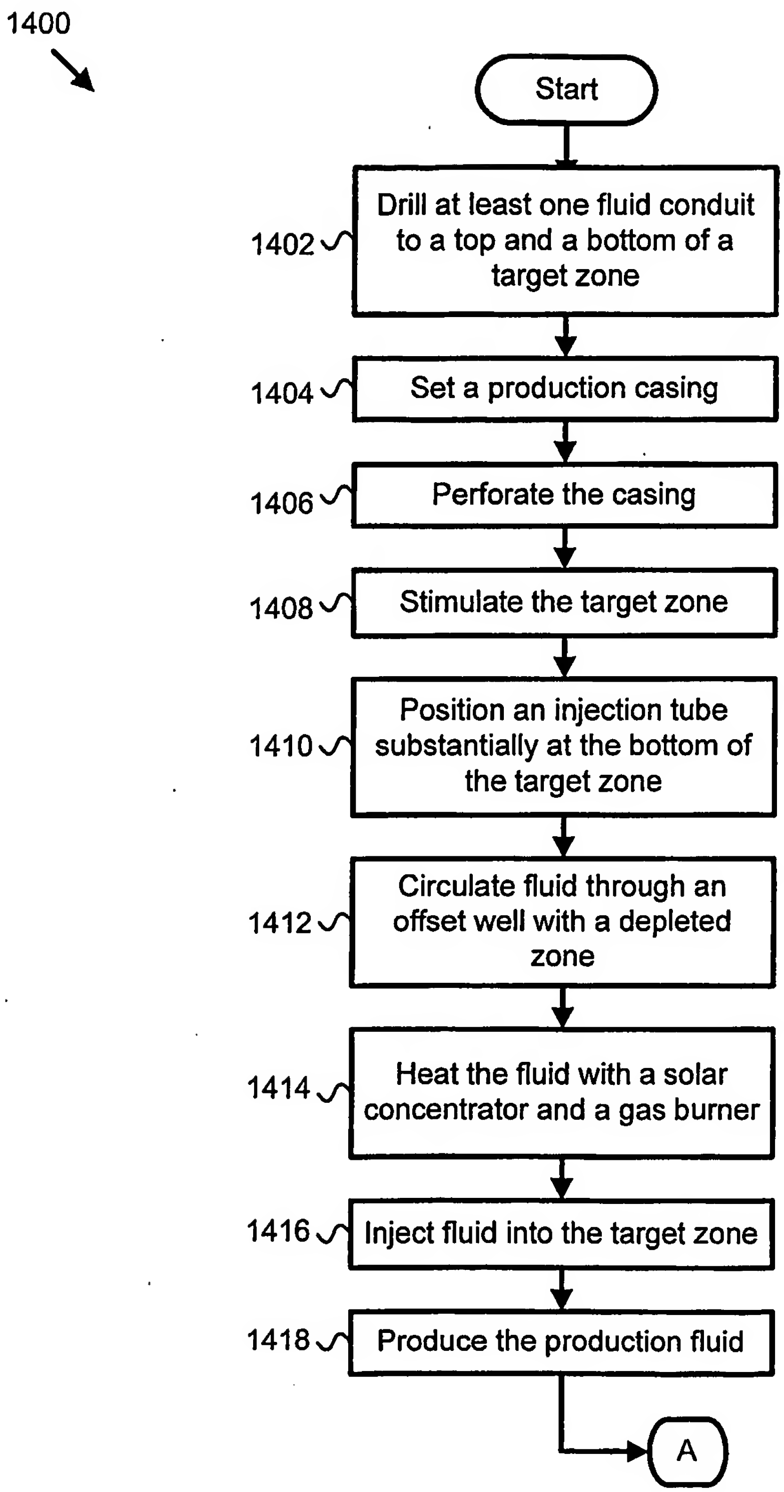
1400
Start
1402
Drill at least one fluid conduit to a top and a bottom of a target zone
1404
Set a production casing
1406
Perforate the casing
1408
Stimulate the target zone
1410
Position an injection tube substantially at the bottom of the target zone
1412
Circulate fluid through an offset well with a depleted zone
1414
Heat the fluid with a solar concentrator and a gas burner
1416
Inject fluid into the target zone
1418
Produce the production fluid
A

Fig. 14A

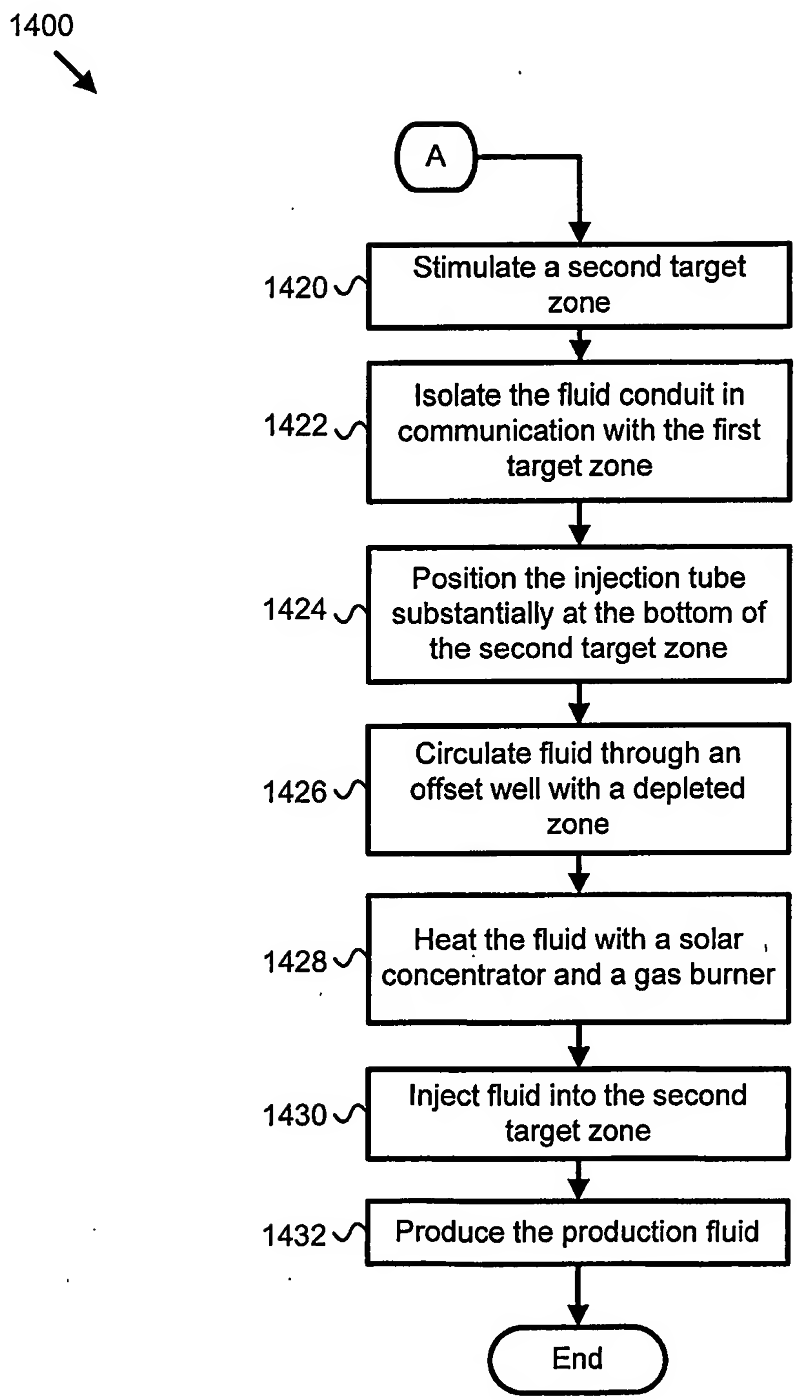
1400
A
1420 Stimulate a second target zone
1422 Isolate the fluid conduit in communication with the first target zone
1424 Position the injection tube substantially at the bottom of the second target zone
1426 Circulate fluid through an offset well with a depleted zone
1428 Heat the fluid with a solar concentrator and a gas burner
1430 Inject fluid into the second target zone
1432 Produce the production fluid
End

Fig. 14B

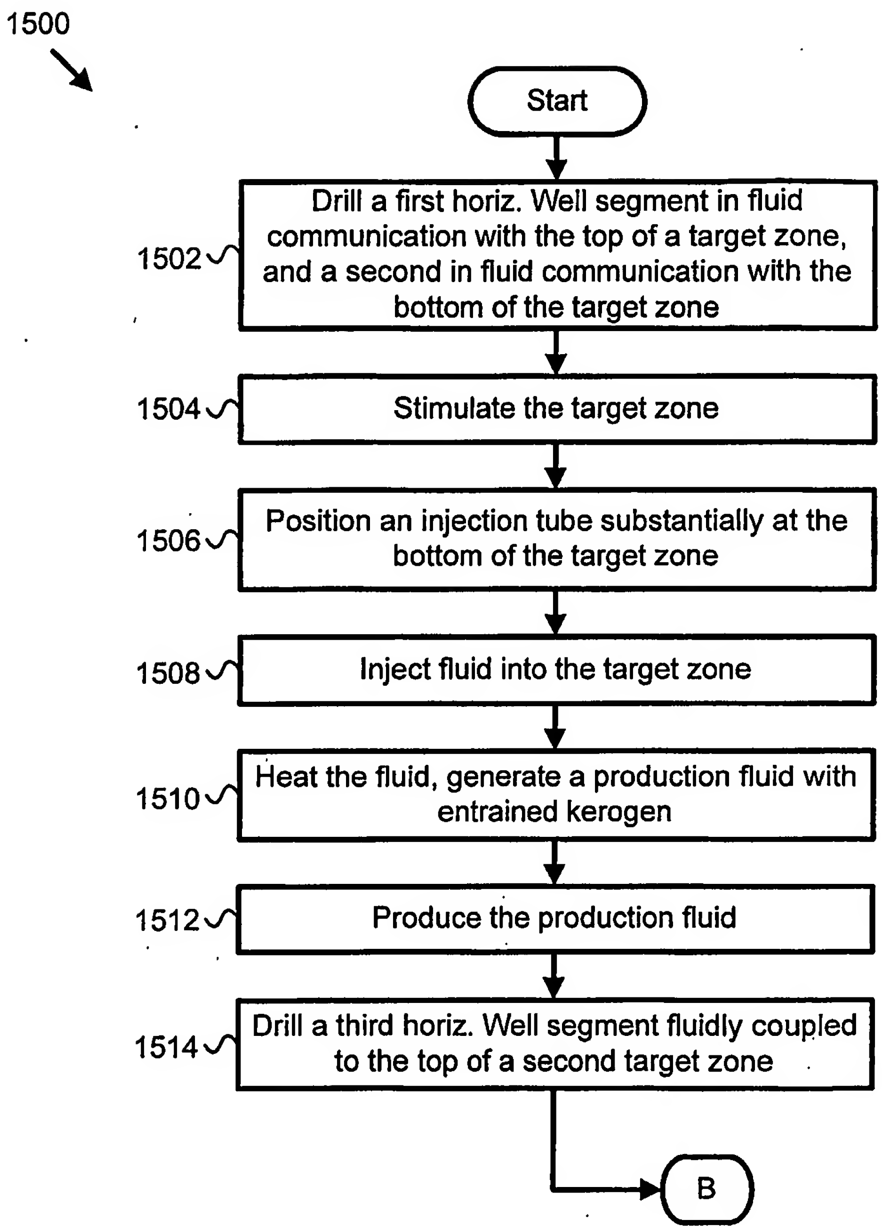
1500
Start
1502
Drill a first horiz. Well segment in fluid communication with the top of a target zone, and a second in fluid communication with the bottom of the target zone
1504
Stimulate the target zone
1506
Position an injection tube substantially at the bottom of the target zone
1508
Inject fluid into the target zone
1510
Heat the fluid, generate a production fluid with entrained kerogen
1512
Produce the production fluid
1514
Drill a third horiz. Well segment fluidly coupled to the top of a second target zone
B

Fig. 15A

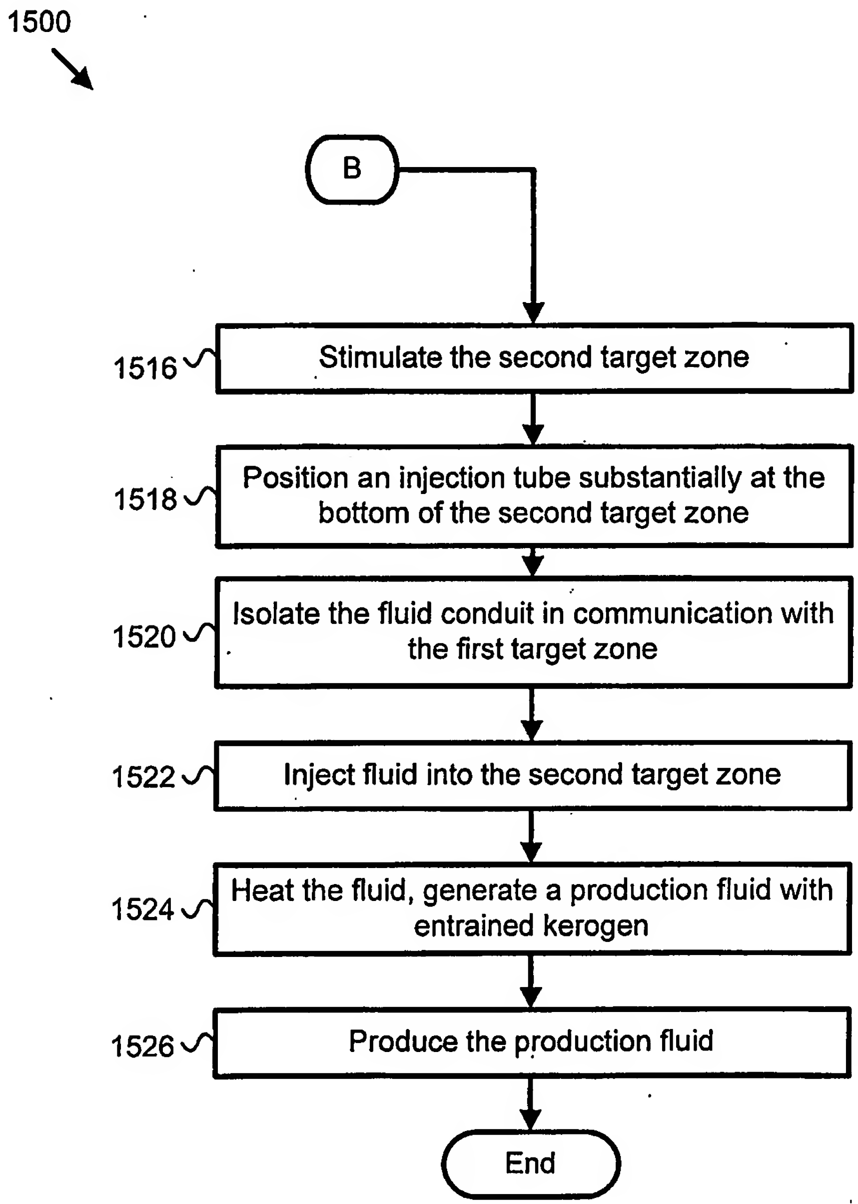
1500
B
1516
Stimulate the second target zone
1518
Position an injection tube substantially at the bottom of the second target zone
1520
Isolate the fluid conduit in communication with the first target zone
1522
Inject fluid into the second target zone
1524
Heat the fluid, generate a production fluid with entrained kerogen
1526
Produce the production fluid
End

Fig. 15B